COMMONWEALTH OF VIRGINIA
Department of Environmental Quality

Intra-Agency Memorandum

DATE: September 30, 2010

SUBJECT: Engineering Evaluation of Prevention of Significant Deterioration (PSD) Permit Application Submitted by Dominion for Warren County Power Station Registration No. 81391

TO: Amy T. Owens, Director, Valley Regional Office

FROM: Anita Riggleman, Senior Environmental Engineer, Valley Regional Office

AIR PERMIT MANAGER REVIEW: *JRP – signed*

DEPUTY REGIONAL DIRECTOR REVIEW: *ATO – signed*

I. Executive Summary

Virginia Electric and Power Company (Dominion) has proposed to construct and operate a combined-cycle electric power generating facility in Warren County with a nominal generating capacity of 1280 megawatts (MW) at ISO (International Organization for Standardization) conditions. Prevention of Significant Deterioration (PSD) permitting is triggered because, as a fossil fuel-fired steam electric plant of more than 250 million British thermal units (Btus) heat input capacity, the proposed facility is a major source under 9 VAC 5 Chapter 80. The proposed facility has the potential to emit more than 100 tons per year each of nitrogen oxides (NO_x), particulate matter having an aerodynamic diameter equal to or less than ten micrograms (PM-10), particulate matter having an aerodynamic diameter equal to or less than 2.5 micrograms (PM-2.5), carbon monoxide (CO), and volatile organic compounds (VOC). Potential emissions of sulfuric acid mist exceed the PSD significance level and are therefore subject to PSD review.

The following table shows the distances between the proposed plant site and the closest Class I areas:

Table 1. Distance of proposed plant from Class I areas (km)

Class I area	Distance from proposed plant (km)
Shenandoah National Park (SNP)	7.1
Dolly Sods Wilderness Area (West Virginia)	100
Otter Creek Wilderness Area (West Virginia)	122
James River Face Wilderness Area	187

PSD regulations provide reviewing authority to Federal Land Managers (FLMs) of Class I areas that may be affected by emissions from the proposed facility. In accordance with Memoranda of Understanding (MOU) between the Virginia Department of Environmental Quality (DEQ) and the respective FLMs, both the National Park Service (NPS) and the National Forest Service (NFS) are given a 60-day review and comment period once provided notification that the application is considered complete. Within the first 30 days of the review period, the FLMs are asked whether or not they will provide a finding of adverse impact on visibility as a result of the proposed facility. FLMs may comment on any aspect of permit processing, but are specifically charged with protecting Air Quality Related Values (AQRVs) within the Class I areas.

PSD permit review includes a rigorous analysis of Best Available Control Technology (BACT). PSD applicants are required to provide a "top down" analysis of all technically and economically feasible control technologies. The applicant is required to employ the most stringent level of control that cannot be demonstrated to be either technically or economically infeasible. Economic feasibility takes into consideration the cost of controls required at similar recently permitted facilities.

Dominion purchased the previously permitted CPV-Warren site which was never constructed. According to Dominion, a new PSD permit is necessary to meet current demand and due to technological advances in turbine equipment. The application was treated as a new application. Once the new permit is issued, the current Dominion – Warren permit issued 7/30/04 as amended 3/29/06, 6/5/07, 1/14/08, and 9/9/09 will be superseded.

II. Introduction and Background

On January 19, 2010, the Valley Regional Office of the Department of Environmental Quality (VRO-DEQ) received an application dated January 18, 2010, from Dominion for a PSD permit to construct and operate a combined-cycle electric generating facility in Warren County. A revised application dated April 2010 was received on April 27, 2010.

A. Site Information

The proposed site for Dominion – Warren is a 38.6-acre parcel in the Warren Industrial Park, approximately one mile north of Interstate Route 66. The site is located in a developed area of the parcel consisting of approximately 22.7 acres.

The UTM coordinates of the proposed site are 744.61 Easting and 4317.04 Northing. The project will be located at a base elevation of 570 feet mean sea level. The nearest terrain to exceed stack height is at 746.95 Easting and 4312.10 Northing, approximately 5.46 km southeast of the proposed facility.

There is gently rolling terrain around the proposed site. The nearest residence to the proposed facility site is located approximately 1,500 feet to the southwest (a single residence, not a development). The nearest school (A. S. Rhodes Elementary School) is approximately four kilometers from the site perimeter. There is both a nursing home (Royal Haven Nursing Home) and a hospital (Warren Memorial Hospital) within approximately 4.5 km of the site perimeter. Other air pollution sources within one mile of the facility are DuPont Automotive and Toray Plastics (America), Inc.

There are two Class I areas within 100 km of the proposed facility: SNP (7.1 km from proposed site) and the Dolly Sods Wilderness Area (100 km from proposed site).

B. Site Suitability

In accordance with Section 10.1-1307 E of the Air Pollution Control Law of Virginia, consideration has been given to the following facts and circumstances relevant to the reasonableness of the activity involved:

1. *The character and degree of injury to, or interference with safety, health, or the reasonable use of property which is caused or threatened to be caused:*

   The activities regulated in this permit have been evaluated consistent with 9 VAC 5-50-260 (Best Available Control Technology) and 9 VAC 5-60-320 (Toxics Rule) and have been determined to meet these standards where applicable. Please see Section IV.D.2 for a description of the Best Available Control Technology standards included in the permit. Please refer to Section IV.B for more information on the applicability of the Toxics Rule to the proposed facility.

   As a fossil fuel-fired steam electric generating plant having heat input greater than 250 million British thermal units per hour, the proposed facility is a major stationary source according to 9 VAC 5-80-1615 C. In accordance with PSD regulations, air quality modeling was conducted to predict the maximum ambient impacts of criteria pollutants emitted by the proposed source. Predicted impacts from CO (1-hour and 8-hour averaging periods), PM-10 (annual averaging period), and NO_2 (annual averaging period) were below applicable modeling significant impact levels (SILs) and well below applicable primary and secondary air quality standards. No further analyses were required for these pollutants at the indicated averaging periods. However, modeled concentrations for NO_2 (1-hour averaging period), PM-10 (24-hour averaging period), and PM-2.5 (24-hour and annual averaging periods) exceeded the applicable SILs. Therefore, a cumulative impact analysis for these pollutants and averaging periods was necessary. The predicted impacts for NO_2, PM-10, and PM-2.5 from the cumulative impact analysis were less than the applicable National Ambient Air Quality Standards (NAAQS). Hence, the project will not cause or contribute to a NAAQS violation.

Dominion's project is proposed to be sited within 7.1 kilometers of SNP, a protected Class I area. As a result, Dominion must demonstrate that emissions from its proposed project will not cause an adverse impact on air quality and air quality related values (AQRVs) within SNP, in addition to any modeling that may be warranted in other areas surrounding the proposed site. Accordingly, Dominion, in consultation with DEQ and NPS staff, conducted extensive modeling to evaluate air quality effects within SNP. The modeling results for SNP are discussed in Attachment C.

The emissions of toxic pollutants from electric generating units such as those proposed by Dominion - Warren are subject to the standards in 9 VAC 5-60-300 *et seq*. Dominion calculated the emissions of toxic pollutants from all of the emission units proposed for the site. Dominion modeled emissions of toxic pollutants for which proposed emissions exceeded the thresholds in 9 VAC 5-60-320 (acrolein, formaldehyde, cadmium, chromium, and nickel). Modeling demonstrated that proposed emissions of acrolein, formaldehyde, cadmium, chromium, and nickel are well below (less than 3 %) the associated Significant Ambient Air Concentrations (SAACs).

It should be noted that in a letter dated September 1, 2010, Dominion offered to obtain NO_x emissions offsets or emission reduction credits (ERCs) at a 1.15:1.00 ratio. Since the previous CPV-Warren permit contained offsets as required by the local use permit from Warren County and the June 29, 2004 directive of the State Air Pollution Control Board, Dominion offered to maintain the previously obtained offsets and also obtain additional offsets at a minimum of the 1.15:1.00 ratio. Dominion has indicated that the existing West Virginia offsets (from World Kitchen and approved by DEQ in a letter dated November 13, 2007) will remain valid and Dominion has not yet indicated from whom they will obtain the remaining emissions offsets. The draft permit incorporates the NO_x offsets requirements into a mitigation plan to address potential impacts in the Shenandoah National Park Class I Area. The proposed mitigation plan requires reduction and/or mitigation of NO_x emissions from the site by purchasing NO_x emission offsets allowances or obtaining reductions from one or more facilities in specified nearby geographic areas.

Results of modeling conducted for emissions from the proposed facility show compliance with the health-based NAAQS for all pollutants. Furthermore, single source and cumulative modeling analyses indicate that the proposed project will not result in a violation of any PSD increment. Accordingly, approval of the proposed permit is not expected to cause injury to or interference with safety, health, or reasonable use of property.

2. *The social and economic value of the activity involved:*

The social and economic value of the facility submitting the application has been evaluated relative to local zoning requirements. The local official has deemed this activity not inconsistent with local ordinances. The signed Local Government Form is attached.

The proposed Dominion - Warren facility will generate electricity using only clean-burning natural gas. The availability of clean fuel electric generation facilities is necessary if operation of conventional coal-fired power plants is to be reduced or replaced. Although it is not guaranteed that regional coal-powered generation will be reduced if clean-burning plants such as the Dominion - Warren project are built, if they are not built, it is certain that electricity demand will continue to be met through use of the older, dirtier facilities. Construction of clean-burning, efficient generation plants such as the proposed Dominion - Warren facility creates the potential for regional SO_2 and NO_x reductions resulting from displacement of older, more polluting forms of electricity generation.

3. *The suitability of the activity to the area in which it is located:*

Consistent with the Board's Suitability Policy dated 9/11/87, the activities regulated in this permit are deemed suitable as follows:

(i) *Air Quality characteristics and performance requirements defined by SAPCB regulations:*

This permit is written consistent with existing applicable regulations. The source is a source of toxics emissions and has been modeled and shows compliance with the applicable SAACs. The emissions for criteria pollutants associated with this permit have likewise been modeled and have been shown through modeling to not cause or contribute to a violation of the ambient air quality standards or allowable increments within any Class I or Class II areas.

Because of the proximity of the proposed site to SNP, PSD regulations require that Dominion conduct extensive modeling analyses to determine potential impacts of the proposed facility on air quality related values (AQRVs), as designated by the Federal Land Managers (National Park Service). The modeling results are discussed in Attachment C.

(ii) *The health impact of air quality deterioration which might reasonably be expected to occur during the grace period allowed by the Regulations or the permit conditions to fix malfunctioning air pollution control equipment:*

Condition 68 of the permit requires the facility to notify the Regional Office within four business hours of discovery of any malfunction of pollution control equipment.

(iii) *Anticipated impact of odor on surrounding communities or violation of the SAPCB Odor Rule:*

No violation of Odor requirements is anticipated as a result of the proposed project.

4. *The scientific and economic practicality of reducing or eliminating the discharge resulting from the activity:*

The state NSR program as well as the PSD and Non-Attainment programs require consideration of levels of control technology that are written into regulation to define the level of scientific and economic practicality for reducing or eliminating emissions. By properly implementing the Regulations through the issuance of the proposed permit, the staff has addressed the scientific and economic practicality of reducing or eliminating emissions associated with this project.

The permit requires numerous pollution control strategies that will result in reduction of emissions. These include pollution prevention techniques such as use of clean fuels, good combustion practices, and clean burning "low-NO_x" lean premix burners as well as add-on control (SCR for NO_x removal and an Oxidation Catalyst for CO, VOC, and VOC toxic pollutant control) (see draft permit Conditions 2-4, 11, 12 and 13). Pollution prevention measures have been included in the draft permit, such as a requirement to use ultra-low sulfur (no more than 0.0015 % by weight) oil in emergency equipment (Condition 24), and a limit on ammonia emissions (not currently a regulated pollutant) (Condition 20). Feasibility of obtaining further emission reductions was reviewed through the rigorous "top-down" Best Available Control Technology (BACT) requirements of PSD review. No additional controls were found to be technically and economically feasible.

C. Project Summary

Dominion has applied for a permit to construct and operate a combined-cycle electric power generating facility with a nominal generating capacity of 1280 megawatts (MW). The proposed facility is comprised of three combustion turbine (CT) generators, each having a heat recovery steam generator (HRSG) driving a common steam turbine (ST) for additional electricity generation. Each HRSG has a duct burner (DB) for supplemental firing. The CT-HRSG arrangement is commonly called combined cycle. The proposed facility also includes an auxiliary boiler, an emergency firewater pump, an emergency generator, a fuel gas heater, three turbine inlet chillers, and a distillate oil storage tank.

Dominion originally requested that the proposed permit allow three optional plant configurations, each having a different combustion turbine manufacturer. On September 1, 2010, Dominion submitted a letter requesting the withdrawal of two of the three options. Therefore, the proposed CT generators will be Mitsubishi M501 GAC units.

The proposed facility is capable of operating in either a gas or steam cycle. In the gas cycle, the CTs will fire natural gas to produce electricity. The steam cycle provides increased efficiency by employing the HRSGs to recover otherwise lost heat from the CT exhaust and using it to create steam and drive the ST generator to produce additional electricity. The steam that exhausts the ST generator is cooled and condensed for reuse in the steam cycle. The combined system will provide approximately 1280 MW of nominal power output.

Total proposed emissions from the facility are shown below.

Table 2. Total emissions from proposed Dominion - Warren project (tons/yr)

Pollutant	**Emissions**
NO_x	330.7
CO	374.9
SO_2	12.4
VOC	240.3
PM-10	216.1
PM-2.5	215.6
Sulfuric acid mist	9.5
Formaldehyde	6.34
Acrolein	0.176
Cadmium	0.00551
Chromium	0.00702
Nickel	0.0105

Note: Emissions of regulated toxic pollutants other than formaldehyde, acrolein, cadmium, chromium, and nickel are below permitting exemption thresholds and were therefore not included in Table 2.

The following federal regulations apply to the proposed facility:

- PSD permitting regulations for emissions of NO_x, PM-10, PM-2.5, CO, VOC, and sulfuric acid mist (H_2SO_4)
- New Source Performance Standard (NSPS), 40 CFR 60, Subpart KKKK applies to the combustion turbines
- New Source Performance Standard (NSPS), 40 CFR 60, Subpart Dc applies to the auxiliary boiler and the fuel gas heater
- New Source Performance Standard (NSPS), 40 CFR 60, Subpart IIII applies to the emergency generator and fire water pump

- Maximum Achievable Control Technology (MACT), 40 CFR 63, Subpart ZZZZ applies to the emergency generator and fire water pump

- 40 CFR Part 75, Title IV Acid Rain Program

- 40 CFR Part 70, Title V Operating Permit Program (application is due within one year of startup)

- 9 VAC 5 Chapter 140, NO_x Budget Trading Program, Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program, CAIR NO_x Ozone Season Trading Program, and CAIR SO_2 Annual Trading Program

Additionally, the facility is subject to state permitting requirements including a state regulation for combustion sources (9 VAC 5-40-880 *et seq.*), and numerous general provisions.

The Combustion Turbine MACT, 40 CFR 63, Subpart YYYY, applies to combustion sources located at major sources of HAP. Dominion - Warren is a minor source of HAPs and therefore is not an affected source under the Combustion Turbine MACT.

D. Process/Equipment Description

Dominion has proposed installation of the following combustion turbines:

- Three Mitsubishi natural gas-fired combustion turbine generators (Model M501 GAC), each rated at 299,600 kW (CT-1, CT-2, and & CT-3); and

- Three heat recovery steam generators (HRSG) with supplementary natural gas-fired Duct Burners, each rated at 500 MMBtu/hr heat input (DB1, DB2, & DB3).

Dominion has proposed the installation of the following ancillary equipment:

- One natural gas-fired auxiliary boiler, rated at 88.1 MMBtu/hr heat input (B-1);

- One natural gas-fired fuel gas heater, rated at 52.0 MMBtu/hr heat input (GH-1);

- Three turbine inlet chillers (600,000 gal/hr) (IC-1, IC-2, & IC-3);
- One diesel-fired Emergency Fire Water Pump, rated at 298 bhp (2.3 MMBtu/hr heat input) (FWP-1);
- One diesel-fired Emergency Generator, rated at 2,193 bhp (16.91 MMBtu/hr heat input) (EG-1); and
- One 6,000-gallon distillate oil storage tank (ST-1).

Combustion Turbine Generators (CT)

Each gas turbine power block will include an advanced firing temperature combustion turbine air compressor section, gas combustion system (utilizing dry, low-NO_x combustors), power turbine, and a generator.

The gas turbine is the main component of a combined-cycle power system. First, air is filtered, cooled and compressed in a multiple stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Lean pre-mix dry low-NO_x combustors minimize NO_x formation during natural gas combustion. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator.

The exhaust gas exiting the power turbine in the combined-cycle turbines is ducted to an unfired boiler commonly known as an HRSG where steam is produced to generate additional electricity in a steam turbine generator. Natural gas-fired duct burners located within the HRSGs are used for supplementary firing to increase steam output.

The combustion turbines are designed to operate in the dry low-NO_x mode at loads from approximately 60 percent up to 100 percent rating and will normally be taken out of service for scheduled maintenance, or as dictated by economic or electrical demand conditions.

Heat Recovery Steam Generators (HRSG) with Duct Burners (DB)

The proposed facility will use three HRSGs, one for each CT, which will use waste heat to produce additional electricity. Each HRSG will act as a heat exchanger to derive heat energy from the CT exhaust gas to produce steam that will be used to drive a Steam Turbine generator (ST). A horizontal, natural circulation, three-pressure level Heat Recovery Steam Generators (HRSGs) system will extract heat from the exhaust of each proposed combined-cycle gas turbine. Exhaust gas entering the HRSG at approximately 1,100 °F will be cooled to 200 °F by the time it leaves the HRSG exhaust stack. Steam production in the HRSGs will be augmented using duct burners (DBs) that will be fired by natural gas. The proposed DBs will have a firing rate of 500 MMBtu/hr each. The heat recovered is used in the combined-cycle plant for additional steam generation and natural gas/feedwater heating. Each HRSG will include high-pressure superheaters, a high-pressure evaporator, high-pressure economizers, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. The air-cooled condenser will condense the steam exhausting from the ST. As the steam is condensed, the condensate flows to the condensate receiver tank. Control devices such as selective catalytic reduction (SCR) and oxidation catalysts will be installed to control NO_x and CO, respectively.

There will be a stack flue for each HRSG. Each stack will be equipped with a Continuous Emissions Monitoring System (CEMS). The height of the stack flues is proposed to be approximately 175 feet above grade.

Steam Turbine (ST)

The proposed project includes one reheat, condensing steam turbine designed for variable pressure operation. The high-pressure portion of the steam turbine receives high-pressure super-heated steam from the HRSGs, and exhausts to the reheat section of the HRSGs. The steam from the reheat section for the HRSGs is supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the surface condenser. The steam turbine set is designed to produce up to approximately 539 MW of electrical output (including duct firing operations).

Turbine Inlet Chillers (IC-1, IC-2, & IC-3)

Small cooling towers will be incorporated to provide cooling to the chillers used in the inlet cooling system for each turbine. Each of the three turbine inlet chillers (one for each proposed natural gas fired combustion turbine) is equipped with a 6-cell cooling tower.

The proposed facility will include three turbine inlet chillers (IC-1, IC-2, & IC-3). Each proposed turbine inlet chiller is rated at 600,000 gallon per hour.

Auxiliary Boiler (B-1)

The proposed facility will include an auxiliary boiler (B-1). The auxiliary boiler will provide steam to the ST at start-up and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the CTs or ST. The proposed B-1 will be fired with natural gas, with a firing rate of 88.1 MMBtu/hr. Dominion requests the boiler to be permitted to operate without annual operating restrictions and the air quality modeling analysis reflects this assumption.

Fuel Gas Heater (GH-1)

The proposed facility will include a fuel gas heater (GH-1). The heater will be used to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The proposed GH-1 will be fired with natural gas only and have a firing rate of 52.0 MMBtu/hr.

Diesel-Fired Emergency Generator (EG-1)

The proposed facility will include a 2,193 bhp (16.91 MMBtu/hr) diesel-fired emergency generator that will be operated up to 500 hours per year. The emergency generator will provide power in emergency situations for turning gears, lube oil pumps, auxiliary cooling water pumps and water supply pumps. Testing and maintenance operation of the emergency generator will be limited to 52 hours per year. The emergency diesel generator is not intended to provide sufficient power for a black start. The proposed permit prohibits the emergency generator from operating for testing and maintenance during a CT startup.

Diesel-Fired Fire Water Pump (FWP-1)

The proposed project will include a 298 bhp (2.30 MMBtu/hr) diesel-fired fire water pump operated as a fire water pump driver. The unit will be limited to 500 hours per year, including monthly testing and maintenance. Testing and maintenance operation of the fire water pump will be limited to 52 hours per year. The proposed permit prohibits the fire water pump from operating for testing and maintenance during a CT startup.

Distillate Oil Storage Tank (ST-1)

The proposed project will include a 6,000-gallon distillate oil storage tank to provide fuel for the emergency generator and fire water pump.

E. Schedule of Project

VRO received the modeling protocol for Dominion – Warren on January 11, 2010 (dated January 7, 2010) and the initial Form 7 air permit application on January 19, 2010 (dated January 18, 2010). Application amendment information was submitted by Dominion and received on February 12, 2010 (dated February 12, 2010), March 17, 2010 (dated March 16, 2010), April 14, 2010 (dated April 14, 2010), April 27, 2010 (dated April 23, 2010), June 28, 2010 (dated June 24, 2010), July 6, 2010 (dated July 2, 2010), July 14, 2010 (dated July 14, 2010), August 27, 2010 (dated August 27, 2010), September 3, 2010 (dated September 2, 2010), and September 24, 2010 (dated September 24, 2010) and supplemental information was received April 27, 2010 (dated April 26, 2010), May 21, 2010 (dated May 20, 2010), July 27, 2010 (dated July 27, 2010), August 6, 2010 (dated August 6, 2010), August 24, 2010 (dated August 24, 2010), September 1, 2010 (dated September 1, 2010 – 2 items), September 3, 2010 (dated September 2, 2010), and September 24, 2010 (dated September 24, 2010). The target date for startup and electrical generation is 2014-2016.

III. Emissions Calculations

A. Criteria Pollutants

Proposed emissions are primarily products of combustion from the combined cycle units and duct burners. There are also emissions from the auxiliary boiler, fuel gas heater, emergency generator, the emergency firewater pump, three turbine inlet chillers, and the distillate oil storage tank.

Emissions from the combined-cycle units vary depending on ambient temperature, relative humidity, and percent of operating capacity ("load") of the unit. The CT manufacturer - Mitsubishi - provided criteria pollutant emissions for 16 operating scenarios reflecting various temperature, humidity, and load conditions. Emissions for all 16 operating scenarios (identified as Case 1 through Case 16) are shown in Table B-2 in Appendix B of the application. SO_2 emissions are based on use of natural gas having a sulfur content of 0.1 grains per 100 standard cubic feet of gas, the maximum sulfur content allowed by the proposed permit.

Short-term emissions for the CTs and DBs have been based on the maximum hourly emission rates ("worst-case" from all operating scenarios) for each pollutant, as shown in Table 3 below.

Table 3. Mitsubishi operating scenarios having highest short-term emissions (each CT)

Pollutant	Case	% Load	Ambient Temp. (°F)	Relative Humidity (%)	Inlet Chilling (On/Off)	Emissions (lbs/hr)
NO_x	12	100	0	90	Off	25.32
CO	12	100	0	90	Off	17.41
SO_2	12	100	0	90	Off	0.98
VOC	12	100	0	90	Off	6.14
PM-10/ PM-2.5	12	100	0	90	Off	18.0

Note: Case 12 shown above is with Duct Burner operation.

Annual emissions for the CTs were calculated based on the combinations of operating scenarios shown in Table 4 below. The combination, proposed by Dominion in its application, yields a more realistic "worst-case" representation for annual emissions: it is assumed that the facility can operate 8,760 hours per year for each pollutant, but not at worst-case ambient conditions (such conditions would not occur for all 8,760 hours). As listed in Table 8, the worst case CT annual emissions for CO and VOC are based on annual emissions that include the startup and shutdown scenarios shown in Table 4. The worst case CT annual emissions for all other pollutants are based on the combination of CT with duct burner firing at 6,000 hours per year and the CT only at 2,760 hours per year. (Please note that the draft permit requires Dominion to include startup and shutdown emissions of all criteria pollutants in calculating emissions to show compliance with its annual emissions limits.) The maximum annual turbine emissions were calculated in Dominion's application and are included in Attachment A.

Table 4. Mitsubishi operating scenario structure used as basis for annual emissions (each CT)

Pollutant	Hours	Case	% Load	Inlet Chilling (On/Off)	Ambient Temp. (° F)	Relative Humidity (%)	Emissions (lbs/hr)					
							NO_x	CO	VOC	PM-10/ PM-2.5	SO_2	H_2SO_4
NO_x, PM-10/PM-2.5, SO_2[1], H_2SO_4, HAPs	6000	12	100	Off	0	90	25.32	NA	NA	18.0	0.98	0.88
	2760	4	100	Off	0	90	21.70	NA	NA	12.0	0.84	0.40
CO, VOC	1728	Offline	NA	NA	NA	NA	NA	0	0	NA	NA	NA
	811	4	100	Off	0	90	NA	9.91	2.64	NA	NA	NA
	6000	12	100	Off	0	90	NA	17.41	6.14	NA	NA	NA
	125	Hot Start	NA	NA	NA	NA	NA	652.0	605.9	NA	NA	NA
	25	Warm Start	NA	NA	NA	NA	NA	487.6	492.7	NA	NA	NA
	25	Cold Start	NA	NA	NA	NA	NA	408.2	523.0	NA	NA	NA
	46	Shut down	NA	NA	NA	NA	NA	352.3	300.4	NA	NA	NA

[1] SO_2 emissions are based on conversion of all sulfur in fuel to SO_2, so startup and shutdown do not affect SO_2 emissions appreciably.

NO_x, CO, and SO_2 emissions from the auxiliary boiler and fuel gas heater were calculated based on the proposed BACT emission rates for natural gas-fired boilers and heaters provided in Dominion's application. VOC, PM (fuel gas heater only), and lead emissions were calculated using the EPA's AP-42, Section 1.4 (Natural Gas Combustion). PM emissions for the auxiliary boiler were calculated based on vendor data. The auxiliary boiler has a capacity of 88.1 MMBtu/hr and the fuel gas heater has a capacity of 52.0 MMBtu/hr and both will burn natural gas. Annual emissions for the boiler and heater are based on 8760 hours of operation per year. Hourly and annual emissions are shown in Table 5.

Table 5. Emissions from auxiliary boiler (B-1) and fuel gas heater (GH-1)

Pollutant	Auxiliary Boiler (B-1)		Fuel Gas Heater (GH-1)	
	lbs/hr	tons/yr	lbs/hr	tons/yr
NO_x[a]	0.97	4.24	0.57	2.51
CO[a]	3.26	14.27	1.92	8.43
SO_2[a]	0.025	0.108	0.01	0.06
VOC[b]	0.47	2.08	0.28	1.23
PM-10/PM-2.5[c, b]	0.44	1.93	0.39	1.70
Lead[b]	4.3E-05	1.9E-04	2.5E-05	1.1E-04
H_2SO_4[d]	1.9E-03	8.3E-03	1.1E-03	4.9E-03

[a] Based on emission factors from the proposed BACT emission rates for natural gas-fired boilers and heaters.
[b] Based on emission factor from AP-42, Table 1.4-2 (Natural Gas Combustion).
[c] Based on vendor data (auxiliary boiler only).
[d] H_2SO_4 emissions based on a 5% conversion of SO_2 to SO_3.

Particulate emissions from the inlet chillers were calculated using EPA's AP-42 Section 13.4 (Wet Cooling Towers) emission factors and weight distribution of particle size provided by vendor. Annual emissions for the turbine chillers are based on 8760 hours of operation per year. Hourly and annual emissions for each inlet chiller are shown in Table 6.

Table 6. Emissions from each inlet chiller (IC-1, IC-2, and IC-3)

Pollutant	Each Inlet Chiller (IC-1, IC-2, and IC-3)	
	lbs/hr	tons/yr
PM-10	3.6E-02	0.16
PM-2.5	1.1E-04	4.8E-04

Based on emission factors from AP-42 Section 13.4 (Wet Cooling Towers), Table 13.4-1 and weight distribution of particle size provided by vendor.

Emissions from the emergency generator and the emergency fire water pump (EG-1 and FWP-1) were based on the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines. The emergency units will use ultra-low sulfur distillate oil having a maximum sulfur content of 0.0015% by weight per federal requirements. Annual emissions from EG-1 and FWP-1 are based on 500 hours of operation each. Short-term and annual emissions are shown in Table 7.

Table 7. Emissions from emergency equipment (EG-1 and FWP-1)

Pollutant	Emergency Generator (EG-1)		Fire Water Pump (FWP-1)	
	lbs/hr	tons/yr	lbs/hr	tons/yr
NO_x[a]	23.08	5.77	1.96	0.49
CO[a]	12.62	3.16	1.72	0.43
SO_2[b]	2.54E-02	6.34E-03	3.45E-03	8.62E-04
VOC[a, c]	23.08	5.77	1.96	0.49
PM[a]	0.72	0.18	0.10	0.02
PM-10[d]	1.44	0.36	0.20	0.05

[a] Based on emission factors from NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines (reference 40CFR 89.112 Table 1). NO_x emissions are assumed to be worst case as entire NMHC + NO_x emission standard is used for NO_x emission factor.
[b] lb/MMBtu based on fuel sulfur.
[c] VOC = TOC.
[d] Since AP-42 does not provide an emission factor for PM-10, the PM emission rate was multiplied by a factor of 2 to conservatively estimate the contribution of condensables.

A summary of estimated annual emissions from the proposed facility, showing the contribution from each emission unit type, is shown in Table 8.

Table 8. Mitsubishi - Annual emissions of criteria pollutants from proposed facility (tons/yr)

Pollutant	Combined cycle units (CT-1+DB1, CT-2+DB2, CT-3+DB3)	Auxiliary Boiler (B-1)	Fuel Gas Heater (GH-1)	Inlet Chillers (IC-1, IC-2, IC-3)	Emergency Generator (EG-1)	Emergency Firewater Pump (FWP-1)	Total
NO_x	317.70	4.24	2.51	-	5.77	0.49	330.7
CO	348.60	14.27	8.43	-	3.16	0.43	374.9
SO_2	12.27	0.11	6.37E-02	-	6.5E-03	8.8E-04	12.5
VOC	230.76	2.08	1.23	-	5.77	0.49	240.3
PM-10	211.53	1.93	1.70	0.48	0.36	4.90E-02	216.1
PM-2.5	211.53	1.93	1.70	1.45E-03	0.36	4.90E-02	215.6
H_2SO_4	9.54	8.3E-03	4.9E-03	-	-	-	9.5
Lead	0.022	1.89E-04	1.12E-04	-	3.80E-05	5.17E-06	0.02

Emission calculations and supporting documentation for criteria pollutants can be found in Appendix B of Dominion - Warren's revised applications dated April 23, 2010 and August 24, 2010.

B. HAPs/Toxic Pollutants

Hazardous air pollutant (HAP) emissions were calculated to determine whether the proposed facility has the potential to be a major source of HAPs under Title III of the Clean Air Act Amendments of 1990. HAP emissions are summarized in Table 9 below; detailed emission calculations are provided in Table B-5 of Appendix B of Dominion - Warren's revised permit application dated April 23, 2010.

Table 9. Mitsubishi - Potential HAP emissions

Pollutant	Potential emissions	
	lbs/hr	tpy
1,3 Butadiene	2.12E-03	1.19E-02
2-Methylnaphthalene	2.80E-05	8.86E-05
3-Methylchloranthrene	2.10E-06	6.64E-06
7,12-Dimethylbenz(a)anthracene	1.87E-05	5.90E-05
Acenaphthene	8.45E-05	2.72E-05
Acenaphthylene	1.70E-04	4.86E-05
Acetaldehyde	2.54E-01	1.01
Acrolein	4.06E-02	1.76E-01
Anthracene	2.79E-05	1.51E-05
Arsenic	2.08E-03	1.00E-03
Benz(a)anthracene	1.65E-05	1.02E-05
Benzene	9.32E-02	3.42E-01
Benzo(a)pyrene	6.18E-06	5.62E-06
Benzo(b)flouoranthene	2.11E-05	1.14E-05
Benzo(g,h,l)perylene	1.08E-05	6.78E-06
Benzo(k)fluoranthene	6.14E-06	7.65E-06
Beryllium	1.25E-04	6.02E-05
Cadmium	1.15E-02	5.51E-03
Chromium	1.46E-02	7.02E-03
Chrysene	2.88E-05	1.33E-05
Cobalt	8.75E-04	4.21E-04
Dibenzo(a,h)anthracene	8.59E-06	6.23E-06
Dichlorobenzene	1.40E-03	4.43E-03
Ethylbenzene	2.01E-01	8.82E-01
Fluoranthene	8.91E-05	3.25E-05
Fluorene	2.87E-04	8.12E-05
Formaldehyde	1.48	6.34
Hexane	2.10	6.64
Indeno(1,2,3-cd)pyrene	9.96E-06	8.61E-06
Lead	5.21E-03	2.51E-03
Manganese	3.96E-03	1.91E-03
Mercury	2.71E-03	1.30E-03
Naphthalene	1.13E-02	3.87E-02
Nickel	2.19E-02	1.05E-02

PAHs	1.38E-02	6.06E-02
Phenanathrene	7.77E-04	2.52E-04
Propylene oxide	1.82E-01	7.99E-01
Pyrene	7.95E-05	3.69E-05
Selenium	2.50E-04	1.20E-04
Toluene	8.27E-01	3.60
Xylene	4.07E-01	1.76
Total HAPs	NA*	**21.8**
Max Single HAP	-	**6.6**

* Federal major Hazardous Air Pollutant (HAP) source thresholds are annual (tons/yr); there are no short-term total HAP thresholds established.

Total HAPs from the proposed facility would be 21.8 tons per year; the single HAP emitted at the highest rate is hexane at 6.6 tons per year. Major source thresholds for HAPs are 10 tons per year for an individual HAP or 25 tons per year total HAPs. Accordingly, Dominion - Warren is not a major source of HAP and is not subject to requirements under 40 CFR Part 63 Subpart YYYY, the Combustion Turbine Maximum Achievable Control Technology (MACT) standard.

Since the combustion turbines are not subject to the Combustion Turbine MACT, the units are subject to the state toxics standards in 9 VAC 5-60-300 *et seq*. Please see Section IV.B for further discussion of toxics emissions from the proposed facility.

IV. Regulatory Review and Considerations

A. Criteria Pollutants

The proposed facility meets the definition of major source under 9 VAC 5 Chapter 80 Article 8 (Prevention of Significant Deterioration (PSD)) because it is a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr heat input capacity and has the potential to emit more than 100 tons per year of a regulated pollutant. Accordingly, the proposed facility is subject to PSD permitting.

Applicability of PSD review is evaluated on a pollutant-specific basis. 9 VAC 5 Chapter 80 Article 8 defines "significant" emissions increase levels for several regulated pollutants; pollutants for which the proposed net emissions increase exceeds significant levels are subject to PSD review.

Table 10 below compares the maximum proposed net emissions increases from Dominion - Warren with PSD significant increase levels.

Table 10. Proposed emissions increases v. PSD significant increase levels

Pollutant	Maximum Allowable Emissions (tpy)	PSD Significant Increase Levels (tpy)	Subject to PSD review?
NO_x	331	40	Yes
CO	375	100	Yes
SO_2[1]	12.4	40	No
VOC	240	40	Yes
PM	216	25	Yes
PM-10	216	15	Yes
PM-2.5	216	10	Yes
Sulfuric acid mist (H_2SO_4)	9.55	7	Yes
Lead (Pb)[1]	0.02	0.6	No

[1] SO_2 and Lead emissions are also below Article 6 permitting threshold levels in 9 VAC 5-80-1320 C.

The PSD Rule also defines as significant "...any net emissions increase associated with a major stationary source...that would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 $\mu g/m^3$ (24-hour average)." (9 VAC 5-80-1615 C). This trigger could potentially affect all regulated pollutants not already subject to PSD based on emissions (e.g., SO_2 and Pb). The modeling results for all remaining regulated pollutants are less than or equal to approximately 0.2 $\mu g/m^3$. Therefore, the project does not trigger PSD review for other regulated pollutants.

The pollutants subject to PSD review are NO_x, PM, PM-10, PM-2.5, CO, VOC, and sulfuric acid mist. PSD regulations require modeling analysis to demonstrate compliance with the NAAQS and PSD increments (NO_x, PM-10, PM-2.5, and CO). It should be noted that although there is a designated significant increase level for PM, sulfuric acid mist, and VOC, there are no modeling requirements for these pollutants. The details of the modeling analysis are provided in Attachment C.

B. HAPs/Toxic Pollutants

The electric generating units proposed by Dominion - Warren are subject to the toxic pollutant standards in 9 VAC 5-60-300. As a result, Dominion conducted an evaluation of toxic pollutants in comparison to the emission standards in 9 VAC 5-60-300. This evaluation included a modeling analysis for five pollutants for which uncontrolled emissions were above the exemption levels in 9 VAC 5-60-300 (acrolein, formaldehyde, cadmium, chromium, and nickel). The modeling analysis indicates that the impacts of the five pollutants are well below their applicable Significant Ambient Air Concentrations (SAACs). Attachment B includes a table showing emissions of toxic pollutants from the proposed facility compared to the exemption thresholds. Attachment C contains the modeling results.

40 CFR 63 Subpart YYYY, National Emissions Standards for HAPs from Stationary Combustion Turbines, was promulgated March 5, 2004 and applies to CTs located at major HAP sources. According to Dominion's application, the HAP emissions from the proposed Dominion - Warren facility do not exceed major source thresholds for HAPs, i.e., 10 tons per year of a single HAP or 25 tons per year of all HAPs combined. Accordingly, the proposed facility is not subject to the MACT standard. It should be noted that the MACT stipulates oxidation catalyst as one way to comply with the MACT limits (oxidation catalysts not only reduce CO and VOC emissions, they also reduce volatile HAP emissions such as formaldehyde, toluene, acetaldehyde and benzene). Dominion has proposed oxidation catalyst to control CO and VOC from its facility.

C. Modeling Results

The Class I and Class II air quality analyses received were dated July 2 and 14, 2010. Supplemental analyses received were dated August 27, 2010 and September 2, 2010.

The Class I and Class II air quality modeling analyses conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and were performed in accordance with their respective approved modeling methodology that were included in a protocol that was submitted in advance by the proposed facility.

The air quality modeling analyses results show compliance with all applicable NAAQS and PSD increments. The DEQ's air quality modeling analyses technical review memorandum is included as Attachment C.

D. Control Technology Standards and Analysis

1. BACT vs. LAER

The Federal permitting process involves two methods of control technology review: Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER). In geographic locations where ambient pollutant concentrations exceed the NAAQS, permit applicants are required to meet LAER. LAER is defined as the lowest emission limit achieved in practice on a similar design. Only technical and environmental factors are considered, without regard to cost. In areas where pollutant concentrations are within the NAAQS, the applicant must apply BACT. BACT represents the most stringent emission limit that is technically, environmentally, and economically feasible. EPA policy requires that LAER is the first consideration in the BACT analysis. Only when LAER is proven to be environmentally or economically infeasible may BACT be less stringent than LAER. However, in no case may BACT result in an emission rate less stringent than required by federal regulations such as NSPS or MACT requirements. Warren County is considered in attainment for all NAAQS. Therefore a BACT analysis (rather than LAER) is required for emission controls and consequently economic factors are considered.

2. BACT requirements

The EPA guidance document New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting prescribes that for PSD permitting, the most stringent BACT review, otherwise known as "top-down" review, be conducted. The "top-down" method provides that all available control technologies be ranked in descending order of control effectiveness. The applicant first examines the most stringent or "top" alternative. The top alternative is established as BACT unless the applicant demonstrates that technical considerations or energy, environmental, or economic impacts justify that the most stringent technology is not feasible. If the most stringent is eliminated, the next most stringent is considered until BACT is established.

All pollutants subject to PSD review are subject to a "top-down" BACT analysis, as BACT is established on a pollutant basis. For the proposed Dominion - Warren facility, the pollutants include NO_x, CO, VOC, PM, PM-10, PM-2.5, and sulfuric acid mist. Emission units addressed in the BACT determination submitted by Dominion - Warren include the combined-cycle units, the auxiliary boiler, the fuel gas heater, the turbine inlet chillers, the emergency generator, and the emergency firewater pump.

PSD procedures require that the BACT cost feasibility analysis be based upon recent permit determinations for similar facilities. Federal guidance is clear that there can be no fixed or "bright line" cost established as representative of BACT. Rather, the cost of reducing emissions, expressed in dollars per ton, is to be compared with the cost incurred by other sources of the same industry type. A listing of BACT determinations included in the RACT/BACT/LAER Clearinghouse for similar facilities is included as Appendix C in Dominion - Warren's application.

Combined-Cycle Combustion Turbine (CT)

NO_x Control

Combustion turbines and the associated duct burners are responsible for most of the emissions from the facility. The following control technologies were identified by Dominion as applicable to NO_x treatment for combined-cycle combustion turbines:

- Selective Catalytic Reduction (SCR)
- SCONOX™
- Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)
- Dry Low-NO_x (DLN) Combustors
- Water or Steam Injection
- XONON™, LoTO$_x$™, THERMALLONO$_x$™, and Pahlmann™

Of the NO_x control technologies that were reviewed for the Dominion – Warren facility, SCR and SCONOX™ were the two most stringent techniques that have been applied to a combined cycle turbine facility. A discussion of the two technologies follows.

SCR

SCR is a process that involves post combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water through several possible reactions that take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the NH_3 injection system, and high NH_3 slip. SCR using ammonia as a reagent represents the state-of-the-art for back end gas turbine NO_x removal from base load, combined-cycle turbines.

SCONOX™

SCONOX™ is an emerging post-combustion technology that removes NO_x from the exhaust gas stream after formation in the combustion turbine. SCONOX™ employs a potassium carbonate bed that adsorbs NO_x where it reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed over the bed, resulting in the reaction of the potassium nitrates to re-form the potassium carbonate and the ejection of nitrogen gas and water.

SCONOX™ is reportedly capable of achieving NO_x emission reductions of 90% or more for combustion turbine application, and it is currently operating on several small natural gas-fired turbines. The most notable advantage of SCONOX™ over SCR is that it reduces NO_x without the use of ammonia. SCONOX™ thereby eliminates the possibility of "ammonia slip", or emissions of excess (unreacted) ammonia, that is present with use of SCR for NO_x control. Similar to SCR, SCONOX™ only operates within a specific temperature range.

Dominion's application eliminated SCONOX™ as not technically feasible for application to this project since it is no longer being offered for large combustion turbines. SCONOX™ is considerably more complex than SCR, would consume significantly more water, and would require more frequent cleaning and other maintenance.

DEQ concurs with Dominion's conclusion that at the present time, $SCONO_x$™ cannot be considered a feasible control option for the proposed project. Particularly because of its proximity to Shenandoah National Park, it is imperative that the Dominion - Warren facility utilize effective, reliable, proven control methods.

SNCR and NSCR

Two other back-end catalytic reduction technologies, SNCR and NSCR, have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100 °F, with an optimum operating temperature zone between 1,600 and 1,900 °F. Simple-cycle combustion turbines have exhaust temperatures of approximately 1,100 °F, and combined-cycle turbines have exhaust temperatures much lower than simple-cycle turbines. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the proposed combustion turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the proposed combustion turbines.

DLN Combustors

DLN combustion control techniques reduce NO_x emissions without injecting water or steam (hence "dry"). DLN combustors are designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NO_x formation. This is accomplished by producing a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

DLN combustors have been employed successfully for natural gas-fired combustion turbines for more than fifteen years.

Water or Steam Injection

Water or steam injection is also designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NO_x formation. This technology involves the injection of water or steam into the high temperature region of the flame, which minimizes thermal NO_x formation by quenching peak flame temperature.

Water and steam injection has been employed successfully for nearly thirty years, for both natural gas and oil-fired combustion turbines. Water and steam injection remains the state-of-the-art combustion technology for minimizing NO_x emissions for oil-fired combustion turbines.

Water injection is considered to be technically feasible for combustion turbines for natural gas and oil firing operations but would not be employed with DLN burners.

XONON™, LoTO$_x$™, THERMALLONO$_x$™, and Pahlmann™

A number of other combustion turbine NO_x emissions control technologies for combustion turbines are being marketed including XONON™, LoTO$_x$™, THERMALLONO$_x$™, and Pahlmann™. None of these technologies has reached the commercial development stage for large combustion turbines that will be fired with natural gas, and thus none are considered to be technically feasible for application to this project. DEQ concurs that these technologies are not yet commercially available technology suitable for controlling CTs of the size proposed at the Dominion – Warren site.

<u>BACT Determination</u>: Selective Catalytic Reduction (SCR) and Dry Low-NOx (DLN) Combustors

Dominion - Warren has proposed a combination of the remaining identified control options for NO_x: dry low-NO_x combustion and selective catalytic reduction (SCR). The proposed Mitsubishi M501 GAC turbines use a two-stage premixed combustion design resulting in uncontrolled NO_x emissions of 15 ppmvd at 15% O_2 when firing natural gas, the fuel proposed for use by Dominion. The draft permit proposes use of SCR to control NO_x emissions from the CTs to the following level (at 15% O_2):

- 2.0 ppmvd (25.32 lbs/hr)

Compliance with the limits is to be based on a one-hour block average.

From 2007 to 2009, approximately ten projects were permitted at 2.0 ppmvd at 15% O_2 including two LAER determinations. The proposed NO_x emission limits are more stringent than those in any permits issued in Virginia for CTs (with the exception of the CPV-Warren permit which was equal to 2.0 ppmvd). There is one project that was permitted at a NO_x emission rate of 1.5 ppmvd at 15% O_2 in the year 2000. However, this project has not been built and therefore, 1.5 ppmvd at 15% O_2 has not been demonstrated as achievable in practice. With that one exception, the proposed limits are as stringent as any listed in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for electric generating facilities.

Dominion has indicated that the plant is expected to operate as a baseload plant, i.e., at close to 100% loading during most times. However, the proposed turbine units will serve the PJM electric grid (part of the Eastern Interconnection grid) as a stabilizing facility capable of covering large swings in electric demand in short periods of time. As part of this process, the PJM system operator will take control of the units in order to meet the continuously changing demand. These load changes will necessitate ramping operation of the combustion turbines and, if necessary, the duct burners up and down to follow load demand. The permit does not restrict the facility from operating at lower loads and the 2.0 ppmvd limit applies to the operation of the turbines at all load levels except during periods of startup and shutdown. The NO_x emission rate is 0.00724 lb/MMBtu. It should be noted that on a lb/MMBtu basis, the proposed CTs are comparable to those at other combined-cycle power plants.

CO control

Carbon monoxide emissions are formed in the exhaust of a combustion turbine as a result of incomplete combustion of the fuel. Similar to the generation of NO_x emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NO_x emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_x emissions. The applicant proposed good combustion control and an oxidation catalyst to control CO emissions (based on 85% CO control) to the following levels, all corresponding to 15% O_2 as a 1-hour rolling average:

- 1.5 ppmvd without duct burner firing
- 2.4 ppmvd with duct burner firing

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the exhaust stream, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust; and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM-10 and sulfuric acid mist emissions.

CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 °F to 1,100 °F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200 °F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation at part load, or during startup/shutdown will result in less than optimum temperatures and reduced control efficiency.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 0.7 to 1.0 inches of water. Pressure drops in this range correspond roughly to a 0.15 percent loss in power output and fuel efficiency or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

Oxidation catalysts have been employed successfully for two decades on natural gas combustion turbines. An oxidation catalyst is considered to be technically feasible for application to this project.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of CO.

As shown in EPA's RBLC, only two projects have been permitted at CO emission rates below 2 ppmvd at 15% O_2. However, neither of these two projects has been built and thus demonstrated. Typically, CO emission rates of 2 ppmvd at 15% O_2 to 3.5 ppmvd at 15% O_2 are determined to be BACT and LAER. The higher CO emission rates generally account for the higher emissions associated with duct burning.

It should be noted that the lean pre-mix dry low-NO_x combustion employed on the CTs also works to reduce CO emissions. DEQ concurs that the proposed oxidation catalyst control and good combustion practices constitute BACT for CO from the CTs.

DEQ requested a further evaluation of the costs and emission reduction benefits of installing a larger oxidation catalyst to lower the proposed CO emission rate. Dominion submitted an additional BACT review that included a cost analysis that demonstrated that it was not cost effective to increase the control for CO emissions.

VOC control

Formation of VOC emissions in combustion turbines is attributable to the same factors as described for CO emissions above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced primarily by the temperature and residence time within the combustion zone.

An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to carbon dioxide and water vapor. The performance of an oxidation catalyst is affected by the VOCs that are actually emitted. No supplementary reactant is used in conjunction with an oxidation catalyst. An oxidation catalyst is considered to be technically feasible for application to this project.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of VOCs.

VOC emission rates for recently permitted combined-cycle facilities are typically in the range of 1.0 ppmvd at 15% O_2 to 2.0 ppmvd at 15% O_2 as shown in Dominion's summary of EPA's RBLC. However, there are a few projects with both higher and lower emission rates. Most of the projects with emission rates below 1.0 ppmvd at 15% O_2 have not been built.

The applicant has proposed to control VOC using good combustion practices in the CT and an oxidation catalyst. The oxidation catalyst is proposed for the dual purpose of controlling CO emissions and VOC emissions. The applicant proposed VOC limits, based on 30% control by an oxidation catalyst, as follows, all at 15% O_2 and as CH_4 (calculated as a three-hour average):

- 0.7 ppmvd without duct burner firing
- 1.6 ppmvd with duct burner firing

The use of good combustion control and an oxidation catalyst represent BACT for VOC control for the proposed combustion turbines.

PM/PM-10/PM-2.5 control

Particulate matter emissions from combustion turbines are a combination of filterable (front-half) and condensable (back-half) particulate. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which contribute to PM-10 and PM-2.5 but not PM, are attributable primarily to the formation of sulfates and possibly organic compounds.

The most stringent particulate control method demonstrated for gas turbines is the use of low ash and low sulfur fuel. No add-on control technologies are listed in EPA's RBLC. Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is the only control method listed. Add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas turbines. The use of ESPs and baghouses are considered technically infeasible, and do not represent an available control technology. The maximum PM-10 concentrations, including condensable PM-10, from combined cycle combustion units are approximately 0.002 gr/dscf which is lower than 0.01 gr/dscf, which is a typical baghouse performance specification.

Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is considered to be technically feasible for application to this project.

The applicant proposed the use of good combustion practices and pipeline quality natural gas as BACT for PM, PM-10, and PM-2.5 control for the proposed combined-cycle turbines. The following

PM/PM-10/PM-2.5 emission rates were proposed as BACT for the Mitsubishi M501 GAC combustion turbines in Dominion's original application:

- 15.5 lb/hr or 0.0052 lb/MMBtu without duct burner firing
- 21.2 lb/hr or 0.0061 lb/MMBtu with duct burner firing

DEQ staff reviewed source testing data (see Attachment D - "Summary of Filterable PM-10" referenced in the Russell City Energy PSD permit Response to Comments dated 2/4/10 and obtained from Weyman Lee with the Bay Area Air Quality Management District) from a number of similar combined-cycle combustion turbines. Each source test result represents the average of multiple test runs (3 in most cases) performed on the same unit. The data showed average particulate emissions of 4.58 lb/hr, with a high of 10.65 lb/hr. These emission rates include all filterable and condensable particulate emissions. In addition, a PM emission rate of 9.5 lb/hr was required for a recently permitted Siemens SGT6-5000 engine at Carlsbad Energy center in Carlsbad, CA. DEQ requested that the applicant investigate further to see if the proposed turbines could meet these lower emission rates for PM/PM-10/PM-2.5.

Unlike NO_x, CO, or VOC, there are no demonstrated add-on technologies or design changes that are used for control of particulate matter. The specific combustion turbine models that Dominion is considering for this project are more advanced than each manufacturer's comparable models currently in operation. The combustion turbine uses less fuel per kilowatt of power generated. The gain in generation efficiency allows the project to use comparatively less fuel to produce more power. While total fuel use will increase proportionately to the increased output capability of the new machines, the decrease in heat rate means that the gain in electric generation is a greater benefit. Fuel use is related to particulate matter generation because more fuel mass will equal more particulate mass out; however, use of the more efficient turbines will generate particulates at a lower rate (on an electrical output basis) than combustion turbines permitted ten years ago in California and other states. Combustion turbines (GE and Siemens turbine model versions) in California have been permitted at very low emission limits.

Following DEQ's request that Dominion investigate further PM reductions based on the above-referenced test data, Dominion proposed the adjusted emission rates below as BACT for the

Mitsubishi 501GAC turbine based on additional input from the turbine supplier and the California experience. These emission limits represent total particulate matter, filterable plus condensable:

- 12.0 lb/hr or 0.0040 lb/MMBtu without duct burner firing
- 18.0 lb/hr or 0.0052 lb/MMBtu with duct burner firing

According to EPA's RBLC during the time period from 2005-2009, the PM emission limits on a lb/MMBtu basis for combined-cycle power plants ranged from 0.0055 to 0.0210 lb/MMBtu. Therefore, on a lb/MMBtu basis, the proposed CTs are comparable to those at other combined-cycle power plants. DEQ agrees that these emission rates along with limiting the fuel fired in the CTs to pipeline-quality natural gas having a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet) and good combustion practices meets BACT for PM.

SO_2 and Sulfuric acid mist control

Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. Sulfuric acid mist emissions (SO_3/H_2SO_4) result from oxidation of fuel sulfur as well as oxidation of SO_2 by the duct burners and catalysts used for NO_x, CO, and VOC control.

The only technically feasible method for SO_2 and sulfuric acid mist emission control is the use of low sulfur fuels. The use of flue gas desulfurization is not technically feasible because the SO_2 emissions from the proposed combustion turbines are two orders of magnitude lower than emission rates achievable using flue gas desulfurization.

Dominion proposed the following SO_2 and sulfuric acid mist emission rates based on a natural gas heating value of 1,020 Btu/scf for the Mitsubishi M501 GAC combustion turbines:

SO_2

- 0.00028 lb/MMBtu

Sulfuric Acid Mist

- 0.00013 lb/MMBtu without duct burner firing
- 0.00025 lb/MMBtu with duct burner firing

The amount of SO_2 and sulfuric acid mist formation is directly proportional to the amount of sulfur present in the fuel. The applicant proposes to use only natural gas in the CTs to control SO_2 and sulfuric acid mist emissions. The proposed limit is lower than those imposed in other recently permitted projects. DEQ considers the proposed limit and the use of natural gas as a fuel acceptable as BACT for SO_2 and sulfuric acid mist. It should be noted that SO_2 emissions are not subject to PSD or minor NSR review (as indicated in Table 10).

Ammonia (NH_3) control

Ammonia emissions from combined-cycle gas turbine plants using SCR are in the 5 to 10 ppmvd at 15% O_2 range. In order to comply with state pollution prevention requirements, Dominion proposed that ammonia emissions would be limited to 5 ppmvd at 15% O_2.

Although not a regulated pollutant, ammonia, as a precursor to PM-2.5, does affect visibility. DEQ took a closer look at the ammonia emissions from the site due to the proposed site location (7 km from the Shenandoah National Park, a Class I area). A permit issued June 15, 2009 to Kleen Energy Systems LLC in Connecticut limits a Siemens SGT6-5000F turbine to 2.0 ppmvd ammonia as a one-hour average during steady-state operation when burning natural gas. DEQ requested Dominion to evaluate the feasibility of achieving 2.0 ppmvd (1-hour average) during steady state operation (i.e. operating with less than a 5% rate of load change within the CEMS hour) for the proposed combustion turbines.

Dominion stated that their vendors indicate the ability to achieve 2 ppm NH_3 during steady-state conditions, however, at additional capital and O&M costs for additional catalyst and housing, a finer NH_3 injection grid, more precise computer controls, and potentially shortened SCR catalyst life. All of these factors will also require additional maintenance materials and cost to ensure that catalyst or injection nozzle plugging does not occur, which would lead to increased NH_3 emissions.

Upon further review, Dominion agreed to restrict ammonia emissions from the Warren County facility to 2 ppm during steady-state conditions with a maximum of 5 ppm during non-steady-state operations (both as a one-hour average), and the proposed permit includes the restrictions.

Auxiliary Boiler and Fuel Gas Heater

Dominion plans to install an auxiliary boiler and a fuel gas heater. Both units burn only pipeline quality natural gas and are relatively small emission sources when compared to the CTs.

NO_x control

NO_x emissions from the auxiliary boiler and fuel gas heater originate primarily as thermal NO_x. The primary front-end combustion controls for boilers and heaters are low excess air, low-NO_x burners, and ultra low-NO_x burners. SCR can be used to remove NO_x from the exhaust gas stream once NO_x has been formed.

Both ultra low-NO_x burners and SCR are capable of limiting NO_x emissions to approximately 0.011 lb/MMBtu or 9 ppmvd at 3% O_2. Data from EPA's RBLC show that recently permitted emission rates for natural gas-fired boilers and fuel gas heaters less than 250 MMBtu/hr are in the 0.035 lb/MMBtu to 0.060 lb/MMBtu range. However, several projects have been permitted in the 0.010 lb/MMBtu to 0.012 lb/MMBtu range including one boiler permitted at 0.012 lb/MMBtu as LAER and one fuel gas heater permitted at 0.021 lb/MMBtu as LAER.

SCR may be technically feasible to achieve a lower emission rate than using ultra low-NO_x burners alone. Dominion reviewed the costs for applying SCR and found that it was not cost effective at more than $50,000 per ton of NO_x removed.

The applicant proposes to burn only pipeline quality natural gas in the auxiliary boiler and fuel gas heater and to use ultra low-NO_x burners to limit NO_x emissions to 0.011 lb/MMBtu (approximately 9 ppmvd at 3% O_2). DEQ agrees that burning natural gas and using ultra low-NO_x burners is BACT for NO_x for the auxiliary boiler and the fuel gas heater.

CO and VOC control

Available emission control techniques for CO are good combustion practices and oxidation catalysts. These controls are capable of limiting CO emissions to 0.037 lb/MMBtu, which is equivalent to 50 ppmvd at 3% O_2. Data from EPA's RBLC show that recent emission rates for natural gas-fired boilers and fuel gas heaters less than 250 MMBtu/hr is in the range of 0.035 lb/MMBtu to 0.060 lb/MMBtu.

Oxidation catalysts may be technically feasible to achieve lower CO emissions than using good combustion practices alone. Dominion reviewed the costs for applying an oxidation catalyst and found that it was more than $8,000 per ton of CO removed. Dominion proposes to implement good combustion practices in the auxiliary boiler and fuel gas heater to limit CO emissions to 0.037 lb/MMBtu. DEQ agrees that using good combustion practices is BACT for CO for the auxiliary boiler and the fuel gas heater.

For VOC emissions, Dominion proposes to burn only pipeline quality natural gas in the auxiliary boiler and the fuel gas heater and to use good combustion practices to limit emissions to 0.005 lb/MMBtu. Annual VOC emissions from the auxiliary boiler will be limited to 2.1 tons/yr while emissions from the fuel gas heater will be limited to 1.3 tons/yr.

PM/PM-10/PM-2.5 control

Particulate matter emissions from the boiler and fuel gas heater are a combination of filterable and condensable particulate. Good combustion practices and limiting fuel use to only pipeline quality natural gas are proposed by the applicant as BACT for PM/PM-10/PM-2.5 emissions from the auxiliary boiler and fuel gas heater. DEQ agrees that this constitutes BACT for particulate emissions from the boiler and heater. Hourly PM-10/PM-2.5 emissions from the auxiliary boiler and the fuel gas heater will be limited to 0.44 lbs/hr and 0.39 lbs/hr, respectively. Annual PM-10/PM-2.5 emissions from the auxiliary boiler will be limited to 1.9 tons/yr while emissions from the fuel gas heater will be limited to 1.7 tons/yr.

SO_2 and Sulfuric Acid Mist control

Emissions of SO_2 from the auxiliary boiler and fuel gas heater are a result of oxidation of fuel sulfur. Sulfuric acid mist emissions (SO_3/H_2SO_4) are based on a 5% conversion of SO_2 to SO_3 by the boiler and heater.

The applicant has proposed the use of pipeline quality natural gas and good combustion practices as BACT for SO_2 and sulfuric acid mist control for the auxiliary boiler and the fuel gas heater. DEQ considers the proposed controls acceptable as BACT for SO_2 and sulfuric acid mist. It should be noted that SO_2 emissions are not subject to PSD or minor NSR review (as indicated in Table 10).

Emergency Diesel Generator and Diesel Fire Water Pump

The emergency generator will be operated only during interruptions in normal electrical power supply to the facility or for maintenance, testing, and operator training. The emergency fire water pump will be operated only in the event of a plant fire, maintenance, testing, and operator training. Each unit is limited to 500 hours of operation per year. Each unit is also limited to 52 hours (1 hour per week) of operation per year for testing and maintenance.

NO_x control

Because emergency engines must start quickly and change output rapidly to match fluctuating load demands, emergency units produce variations in exhaust temperature and flow rate as well as NO_x concentration and are therefore not well-suited for a selective non-catalytic reduction (SNCR) or an SCR system. Additionally, because of the limited operating hours (a maximum of 500 per year as limited by the permit), control by SCR or SNCR would not be cost effective.

At 500 hours of operation, the maximum annual NO_x emissions for the emergency generator would be 5.8 tons per year and for the fire water pump would be about 0.5 tons per year. The emission factors for NO_x used as the basis for the emergency generator and fire water pump emissions limits are based on the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII), the current federal standard for stationary engines.

Because of the low maximum emissions level at the limited allowed operating hours and the fact that the engines are required to meet the federal standards outlined in the NSPS, Subpart IIII, DEQ concurs that add-on control would not be cost effective for the emergency units and that the proposed emission levels meet BACT.

As also required by the NSPS, Subpart IIII, the permit requires Dominion to use ultra-low sulfur fuel oil in its emergency units. In addition to reducing SO_2 emissions, use of ultra-low sulfur fuel is expected to have the additional benefit of reducing NO_x emissions.

CO control

Because of the limited hours of operation for the emergency units, add-on controls for CO are not practical. The emission factors for CO used as the basis for the emergency generator and fire water pump emissions limits are based on the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines, the current federal standard for stationary engines.

Based on staff research, DEQ considers the federal standards to be acceptable as BACT. At 500 hours of operation, the maximum annual CO emissions for the generator would be 3.2 tons per year and for the firewater pump would be 0.4 tons per year. Given the limited allowable emissions, it is evident that add-on controls would not be cost effective.

PM/PM-10 control

Particulate matter emissions from oil-fired internal combustion engines may result from trace metals present in the fuel, unburned carbon-containing materials and sulfate formation. The use of ultra-low sulfur fuel oil, good combustion practices, and a limitation on operating hours is considered BACT for PM/PM-10/PM-2.5 from the emergency units. The proposed emission rate for PM, based on NSPS Subpart IIII, is 0.20 g/kW-hr for both the generator and the fire water pump. Since AP-42 does not provide an emission factor for PM-10, the PM emission rate was multiplied by a factor of 2 to conservatively estimate the contribution of condensables. Annual PM/PM-10/PM-2.5 emissions from each unit are less than 0.5 ton per year, so DEQ finds the proposal acceptable as BACT for PM/PM-10/PM-2.5 from the generator and fire water pump.

It should be noted that the permit requirement to use ultra-low sulfur fuel per the federal motor vehicle diesel fuel standards (40 CFR 80.500 and 80.520) is expected to result in reduced PM/PM-10 emissions from the emergency equipment, as less sulfur will be available to form sulfates, a fine particulate.

VOC control

VOC emissions from internal combustion units are the result of incomplete combustion. Due to the limited operating hours for the emergency units, add-on controls, even if technically feasible, would not be justifiable economically. The application proposes conservative VOC emission rates equal to the NSPS, Subpart IIII emission limits for non-methane hydrocarbons (NMHC) + NO_x of 6.4 g/kW-hr for the generator and 4.0 g/kW-hr for the fire water pump as BACT.

At 500 hours of operation, the maximum annual VOC emissions for the generator would be 5.8 tons per year and for the fire water pump would be 0.5 tons per year. DEQ concurs with the proposed limits as BACT.

SO_2 control

Because emission levels and Class I impacts of SO_2 are below PSD thresholds, SO_2 is not subject to a BACT review. However, the permit requires use of ultra-low sulfur fuel in the generators (distillate oil having no more than 0.0015% sulfur by weight).

Turbine Inlet Chillers

The only pollutant emitted from the turbine inlet chillers is particulate matter. Dominion plans to install three small 10,000 gal/min turbine chillers for combustion turbine inlet air chilling. Packaged cooling towers are associated with each of these chillers and a drift rate of 0.0005% is inherent in the design of the units. This drift rate is considered BACT based on the top level of control. Emissions of PM/PM-10/PM-2.5 are projected to be less than 1 ton/yr. Due to the very low emissions, no add-on controls are considered economically feasible as BACT.

3. LAER

LAER applies only in nonattainment areas. Because the site of the proposed facility is attainment or unclassified for all pollutants, LAER does not apply. However, in accordance with the 1990 Draft PSD Workshop Manual, LAER technologies have been included as the most stringent technologies in the top-down BACT review.

4. NESHAP (40 CFR Part 61)

National Emission Standards for Hazardous Air Pollutants (NESHAP), found at 40 CFR 61, regulate emissions of specific HAPs from a limited number of source categories. 40 CFR 61 standards are incorporated by reference into Virginia Regulations at 9 VAC 5 Chapter 60, Part II, Article 1 (Rule 6-1). None of these

Part 61 regulations apply to natural gas-fired stationary combustion turbines or the other emissions units proposed for the Dominion-Warren project.

5. RACT

Reasonably Available Control Technology (RACT) standards apply only in nonattainment areas. Because the site of the proposed facility is attainment or unclassified for all pollutants, RACT does not apply.

6. MACT (40 CFR Part 63)

Maximum Achievable Control Technology (MACT) standards, found at 40 CFR 63, designate emission standards for HAPs from specific source categories. 40 CFR 63 standards are incorporated by reference into Virginia Regulations at 9 VAC 5 Chapter 60, Part II, Article 2 (Rule 6-2).

40 CFR 63 Subpart YYYY, National Emissions Standards for HAPs from Stationary Combustion Turbines, was promulgated March 5, 2004 and applies to CTs located at major HAP sources. The potential HAP emissions from the proposed Dominion - Warren facility do not exceed major source thresholds for HAPs, i.e., 10 tons per year of a single HAP or 25 tons per year of all HAPs combined. Accordingly, the proposed facility is not subject to the MACT standard. It should be noted that the MACT stipulates oxidation catalyst as one way to comply with the MACT limits (oxidation catalysts not only reduce CO and VOC emissions, they also reduce HAP emissions such as formaldehyde, toluene, acetaldehyde and benzene). Dominion has proposed oxidation catalyst to control CO and VOC from its facility.

40 CFR 63 Subpart ZZZZ, National Emissions Standards for HAPs for Stationary Reciprocating Internal Combustion Engines, was promulgated June 15, 2004 and applies to stationary reciprocating internal combustion (IC) engines located at major and area sources of HAP emissions. Per 40 CFR 63.6590(c), stationary IC engines subject to Regulations under 40 CFR Part 60 can meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII for compression ignition engines. As mentioned below, 40 CFR 60 Subpart IIII applies to the proposed IC engines and the applicable requirements from Subpart IIII have been included in the permit. Therefore, no further requirements from Subpart ZZZZ apply to the engines.

7. NSPS (40 CFR Part 60)

New Source Performance Standards (NSPS), found at 40 CFR 60, designate emission standards for criteria pollutants (a few regulate HAPs as well) from new emissions units at specific source categories. 40 CFR 60 standards are incorporated into Virginia Regulations at 9 VAC 5 Chapter 50, Part II, Article 5 (Rule 5-5).

There are NSPS that apply to the CTs, the DBs, the auxiliary boiler, the fuel gas heater, the emergency generator, and the fire water pump at the proposed facility, as detailed below:

- *40 CFR 60 Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)*

  Subpart KKKK applies to gas turbines having a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel fired. The subpart also applies to emissions from the associated duct burners. The rule imposes limits on NO_x and SO_2 emissions and monitoring and testing requirements. Using the most conservative assumptions, the NO_x limit in Subpart KKKK is 15 ppm at 15% O_2 and the SO_2 limit must be 0.060 lb SO_2/MMBtu or lower.

  The BACT determinations codified in the permit are more stringent than the NSPS requirements. For example, the NO_x permit limit is 2.0 ppmvd, the fuel sulfur content is limited to 0.0003 % by weight, and the SO_2 permit limit is 0.00028 lb/MMBtu. Testing and monitoring requirements mirror or exceed those in Subpart KKKK.

- *40 CFR 60 Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)*

  Subpart Da applies to electric utility steam generating units capable of combusting more than 250 MMBtu/hr heat input of fossil fuel for which construction began after September 18, 1978. The DBs proposed by Dominion meet the applicability criteria of the rule and are subject to its requirements. However, duct burners regulated under NSPS, Subpart KKKK are exempted from the requirements of NSPS, Subparts Da, Db, and Dc.

- *40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)*

  Subpart Dc applies to steam generating units with a maximum design heat input capacity in the range of 10 MMBtu/hr to 100 MMBtu/hr for which construction began after June 9, 1989. The auxiliary boiler and the fuel gas heater meet the applicability criteria of the rule and are subject to its requirements. The applicable requirements for natural gas burning units have been incorporated into the permit.

- *40 CFR 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)*

  Subpart IIII applies to stationary internal combustion (IC) engines with a displacement of less than 30 liters per cylinder where the model year is 2007 or later, for engines that are not fire pump engines. For fire pump engines, Subpart IIII applies beginning with the model years listed in Table 3 of the subpart. The rule imposes emission standards on NO_X, CO, and PM emissions based on the engine model year and engine use (emergency, fire pump, etc.). The subpart also requires engine owners and operators to use ultra-low sulfur fuel in the generators (distillate oil having no more than 0.0015% sulfur by weight). The applicable requirements for the generator and fire pump engines have been incorporated into the permit.

  Since the generator and fire pump engines will meet the requirements of Subpart IIII, the units do not have any further requirements under 40 CFR 63 Subpart ZZZZ (see above).

- *40 CFR 60 Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels)* is not applicable to the 6,000-gallon distillate oil storage tank proposed by the applicant. Subpart Kb applies only to storage vessels having a capacity of at least 10,566.88 gallons (40 m^3).

V. Compliance Determination

A. Stack testing requirements

The permit requires initial compliance testing for NO_X, SO_2, CO, PM-10, PM-2.5, and VOC from the combined-cycle units. The need for periodic performance testing will be evaluated during processing of the Title V permit for the facility based on the results of the initial testing and operating data. A condition allowing DEQ to require additional testing has been included in the permit.

B. Fuel testing requirements

The permit allows the permittee to use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel to verify that the sulfur content of the natural gas is 0.1 grain or less of total sulfur per 100 standard cubic feet. Alternatively, per 40 CFR 60.4370, the permit allows Dominion to determine the sulfur content of the natural gas by testing using two custom monitoring schedules or an EPA-approved schedule. The permit also requires the permittee to obtain fuel supplier certification for each shipment of distillate oil used in the emergency units.

C. Visible emissions evaluations

A visible emissions evaluation (VEE), concurrent with the initial CT stack test, is required by the permit. Periodic CT stack visible emission inspections, which trigger a VEE according to EPA Method 9 if visible emissions are observed, have been included in the permit.

D. Continuous emissions monitoring systems (CEMS)

The permit requires that the CT stacks be equipped with CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain program) for NO_x and SO_2 (unless an alternative method of determining SO_2 emissions has been approved for that purpose). In addition to providing a means to demonstrate compliance with the permit NO_x limits, the CEMS will satisfy the NSPS Subpart KKKK requirement to monitor NO_x emissions using a CEMS. The permit also requires that the CT stacks be equipped with CEMS meeting the monitoring requirements in 40 CFR 60.13 for CO.

In addition to the CEMS, the draft permit requires Dominion to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance (see Conditions 5 through 9).

E. Recordkeeping requirements

- Compliance with NO_x and CO emission limits for the CCCTs will be determined using Continuous Emission Monitoring Systems (CEMS).

- Compliance with SO_2 emission limits will be determined through fuel sulfur monitoring and records of fuel usage.
- VOC, CO, PM-10, and PM-2.5 emission factors (lb/MMbtu) will be verified during initial compliance testing. Since annual emission limits for these pollutants are based 8760 hours of operation with each unit operating at worst case conditions, compliance with annual emission limits can be demonstrated with fuel throughput records. Accordingly, monthly record keeping of "rolling" 12-month totals is required for natural gas throughput to each turbine and to each duct burner.

Additionally, the permit requires that the following records be kept:

- Time, date, and duration of each CT startup, shutdown, and malfunction period;
- Annual number of startup and shutdown occurrences for each CT calculated monthly;
- Continuous records of heat input and power output for each CT;
- Emissions calculations sufficient to verify compliance with the annual emission limits in Conditions 17, 29, 30, 38, and 39 (calculated monthly as the sum of each consecutive 12-month period), and records sufficient to allow calculation of actual annual emissions from the remainder of the facility. Calculation methods are to be approved by the DEQ;
- CEMS data, calibrations and calibration checks, percent operating time, and excess emissions;
- Annual operating hours of the emergency generator and the fire water pump for emergency purposes and maintenance/testing, calculated monthly as the sum of each consecutive 12-month period;
- Time, date, and duration of operation of emergency generator and fire water pump for maintenance and testing and the operational status of each CT during that time;
- Fuel supplier certifications for distillate oil;
- Records of engine manufacturer data;
- Operation and monitoring records for each SCR system and each oxidation catalyst;
- Records of steady-state vs. non-steady-state operation of each CT unit, the ammonia slip monitoring plan, and ammonia slip monitoring results;
- Scheduled and unscheduled maintenance and operator training;
- Results of all stack tests, VEEs, visible emissions inspections, and performance evaluations;

- Monthly and annual fuel throughput to the auxiliary boiler and fuel gas heater;
- Records of good combustion practices for the auxiliary boiler and fuel gas heater;
- Records for emission offsets; and
- Records of CEMS quality control program.

The records must be available for DEQ inspection and maintained for five years.

VI. Public Participation

A. Applicant Informational Briefing

In accordance with Section 9 VAC 5-80-1775 C of the Regulations, the applicant held an informational briefing at 6:30 p.m. on May 11, 2010 at the Warren County Government Center in Front Royal. As required, the briefing was advertised in the Warren Sentinel and the Northern Virginia Daily at least 30 days in advance (on March 25 and March 19, 2010, respectively).

B. Public Briefing

9 VAC 5-80-1775 J specifies that a briefing be scheduled prior to the public comment period if appropriate. VRO has scheduled a public briefing at 6:30 p.m. on October 7, 2010 at the Warren County Government Center in Front Royal. The briefing requires a 30-day (at minimum) notification period. A legal advertisement for the briefing was placed in the Northern Virginia Daily on September 4, 2010.

C. Public Hearing

In accordance with 9 VAC 5-80-1775 E, VRO will hold a public hearing to accept comments on the air quality impact of the proposed source, alternatives to the source, the control technology required, and other appropriate considerations tentatively scheduled for November 9, 2010 at the Celebration Hall of the North Warren Volunteer Fire Department in Front Royal. A legal advertisement for the hearing will tentatively be published in the Northern Virginia Daily newspaper on October 9, 2010.

D. Documents Concerning Public Comment Period

Copies of the documents used in development of the draft permit were available for review at VRO. Additionally, a copy of Dominion -

Warren's permit application, modeling information and correspondence was placed online at the DEQ website. Upon completion of the application analysis and prior to the public briefing, the permit application, draft permit, and draft engineering analysis and all items contained in the attached Document List were available at the Samuels Public Library and remained available for review throughout the public comment period. The draft permit and draft engineering analysis was also accessible from DEQ's website at www.deq.virginia.gov.

E. Public Comment

The public comment period which runs for at least 45 days and at least 15 days after the public hearing begins on October 10, 2010 and ends on November 24, 2010. All comments received will be recorded, reviewed and a Response to Comments document will be written.

VII. Notification of Other Government Agencies

A. Local Zoning

Because the proposed facility constitutes a new stationary source subject to air permitting regulations, a local governing body certification form is required in accordance with Department policy and § 10.1-1321.1 of the Code of Virginia. On January 25, 2010, the County Administrator for Warren County certified that the proposed facility is fully consistent with local ordinances.

B. Environmental Protection Agency (EPA)

In accordance with 9 VAC 5-80-1765, there are specific notification requirements to advise EPA of sources impacting federal Class I areas. Accordingly, a copy of the permit application, including supplemental addenda, and DEQ's initial letter of determination were provided to EPA Region III. EPA will be provided with a copy of the draft permit and will be notified of the public comment period and the final determination on permit issuance.

C. Federal Land Managers

Because of Dominion-Warren's proximity to SNP (see Table 1), a protected Class I area, DEQ has worked with the Federal Land Managers (FLMs) whose responsibility it is to oversee such areas. In accordance with the Memorandum of Understanding dated March 31, 1993, between DEQ and SNP and the Jefferson National Forest, both the National Park

Service (NPS) and U.S. Forest Service (USFS) were provided copies of Dominion - Warren's permit application and supplemental addenda, most notably the Class I and Class II modeling analyses. Numerous conference calls were conducted between NPS, Dominion, and DEQ to determine an acceptable approach to the Class I air quality analyses, which are reviewed and assessed primarily by NPS. NPS was provided a copy of Dominion - Warren's Class I and Air Quality Related Values (AQRVs) analyses and its review is currently underway.

Upon completion of DEQ's application analysis, DEQ provided the FLMs copies of correspondence generated in reaching its permit determination. On September 3, 2010, DEQ sent both NPS and USFS copies of the preliminary permit determination and provided notification that the application was considered complete and that the FLM 60-day review period had begun. According to 9 VAC 5-80-1765 B, that notification must be provided at least 60 days before the scheduled public hearing on the application. In a letter dated September 13, 2010, the USFS responded to the DEQ notification letter by stating that they did not plan to issue any finding of adverse impact on visibility from the proposed Dominion-Warren facility. Copies of the draft permit and engineering analysis were sent to the FLMs at the beginning of the public comment period.

VIII. Pollution Prevention

The natural gas-fired combined-cycle turbine configuration may itself be considered a pollution prevention alternative in that it produces power much more cleanly (in pounds of pollutant emitted per kilowatt hour of power produced) than conventional coal or oil-fired power plants. The HRSGs are an important factor in clean power generation because they recover heat that would otherwise be lost to the atmosphere and use it to produce additional electrical power.

Site-specific pollution prevention measures have been included as requirements in the permit, such as the following:

- Use of clean fuels (natural gas containing no more than 0.0003 % sulfur by weight in the CTs, auxiliary boiler, and fuel gas heater;
- Use of clean firing technology (lean premix low-NO_x burners);
- In the emergency generator and firewater pump, use of ultra low-sulfur (no more than 0.0015% sulfur by weight) distillate oil. Use of such fuels reduces emissions of not only sulfur dioxide and sulfuric acid mist but also of PM/PM-10/PM-2.5 (a component of which is sulfates) and is expected to reduce NO_x emissions as well.

The permit also includes requirements related to emissions of ammonia from the SCR. Ammonia is injected in the SCR system to induce the catalytic reduction of

NO_x, and, to ensure maximum conversion of NO_x, ammonia in excess of its stoichiometric requirement (the minimum amount required to react with a given amount of NO_x) is used. Any unreacted ammonia remaining is released to the atmosphere and is referred to as "ammonia slip". Although ammonia is not a regulated pollutant, ammonia emissions can nonetheless contribute to condensable particulate, regional haze, and nitrogen deposition. Furthermore, excessive ammonia emissions can indicate poor SCR system performance. Accordingly, the permit includes an ammonia emission limit of 2 ppmvd during steady-state conditions and 5 ppmvd during non-steady-state conditions (both as a one-hour average) for at least 95 % of the time that the SCR is operating and a requirement to submit a plan for monitoring ammonia slip.

IX. Title V Operating Permit (9 VAC 5 Chapter 80, Article 1)

Dominion - Warren is required by Virginia regulations to obtain a federal operating permit under Title V of the Clean Air Act. The Regulations require that Dominion - Warren submit a Title V permit application no later than one year after startup of the facility.

X. Acid Rain Operating Permit (9 VAC 5 Chapter 80, Article 3)

Dominion - Warren is required by Virginia Regulations to obtain a permit under the federal Acid Rain program. Federal regulations require that a complete Acid Rain Program permit application be submitted at least 24 months prior to commencement of operation.

XI. NO_x and SO_2 Trading Programs (9 VAC 5 Chapter 140)

Virginia has established several emissions trading programs (NO_x Budget Trading Program, CAIR NO_x Annual Trading Program, CAIR NO_x Ozone Season Trading Program, and CAIR SO_2 Trading Program) to meet the requirements of EPA's budget trading programs. Electric generation units that have capacities above 25 MW and sell electricity are subject to the restrictions of the trading programs. Accordingly, Dominion – Warren will be required to comply with 9 VAC 5 Chapter 140 upon commencement of operation (first day any of the combustion turbines burn fuel).

The NO_x emission trading program provides an economic incentive to facilities to reduce their NO_x emissions and it provides for construction of new facilities without increasing the total amount of NO_x emitted in the state during the year from affected sources.

The NO_x Budget Trading Programs will establish statewide or regional "caps" on total NO_x emissions from electric generating facilities and other designated sources of NO_x. Sources that apply to the program will be granted an allotment or allowable NO_x emission level for each annual year and for each ozone season. Sources cannot exceed the allotments without purchasing NO_x credits from another program participant in the region. Accordingly, regional NO_x emissions from designated source categories will not increase during the annual year or the ozone season.

The fact that Dominion - Warren is subject to the NO_x trading programs will provide an incentive for the facility to minimize the number of times it starts up its CTs. During CT startup, NO_x emissions from the unit are higher than they are during normal operation. If the facility has too many startups during a given period, it may exceed its NO_x emission allotment. Such an exceedance in the trading program will cost the facility in that it will be required to purchase offsetting NO_x credits.

The units at the Dominion - Warren facility will also be subject to the CAIR SO_2 Annual Trading Program. Since the turbines burn natural gas only, the annual SO_2 emissions from the proposed facility are relatively small.

A December 2008 court decision remanded to 2005 Clean Air Interstate Rule (CAIR) but kept the requirements of CAIR in place temporarily until a new rule could be issued. On July 6, 2010, EPA proposed the Clean Air Transport Rule in a response to the Court remand of the 2005 CAIR. The proposal would replace the CAIR trading programs when final and would require reductions in SO_2 and NO_x emissions that contribute to ozone and fine particulate matter. The Dominion – Warren County Power Station will most likely be subject to the Transport Rule once finalized.

XII. Document List

A list of documents used in preparing the application analysis is included as Attachment E.

XIII. Special Considerations

Mitigation Plan

As has been previously referenced, Dominion offered to obtain NO_x emissions offsets or emission reduction credits (ERCs) at a 1.15:1.00 ratio in a letter dated September 1, 2010. Since the previous CPV-Warren permit contained offsets as required by the local use permit from Warren County and the June 29, 2004 directive of the State Air Pollution Control Board, Dominion offered to maintain the previously obtained offsets and also secure additional offsets. Dominion has indicated that the existing West Virginia offsets (from World Kitchen and approved by DEQ in a letter dated November 13, 2007) will remain valid and additional offsets will be obtained. The draft permit incorporates the NO_x offsets requirements into a mitigation plan to address potential impacts in the Shenandoah National Park Class I Area. The proposed mitigation plan requires reduction and/or mitigation of NO_x emissions from the site by purchasing NO_x emission offsets allowances or obtaining reductions from one or more facilities in specified nearby geographic areas.

XIV. Recommendation

Approval to proceed with public comment period is recommended.

Attachments

Attachment A: Maximum Annual Turbine Emissions with Startups and Shutdowns

Attachment B: Toxic Pollutant Evaluation

Attachment C: DEQ Air Quality Modeling Analysis Memorandum

Attachment D: Summary of Filterable PM-10 from Russell City Energy PSD Permit

Attachment E: Document List

ATTACHMENT A:

Maximum Annual Turbine Emissions with Startups and Shutdowns

ATTACHMENT A

Table B-4 Maximum Annual Emissions with Startups and Shutdowns - Mitsubishi M501 GAC

Operating Parameters - Each Unit

			Potential Emission Rates (Per Turbine)				3x3x1 Configuration
Parameter	Combustion Turbine w/ Duct Firing	Combustion Turbine w/out Duct Firing	Annual Emissions based on DB Firing & CT Only Operating Hour Limits	Annual Emissions Based on CT Only Year-Round	Annual Emissions with Startup and Shutdown	Worst-Case Annual Emissions	Worst-Case Annual Emissions (Total)
Operating Hours	6000 hr/yr	2760 hr/yr					
NOx:	25.3 lb/hr	21.7 lb/hr	105.9 ton/yr	95.0 ton/yr	89.2 ton/yr	105.9 ton/yr	317.7 ton/yr
CO:	17.4 lb/hr	9.9 lb/hr	65.9 ton/yr	43.4 ton/yr	116.2 ton/yr	116.2 ton/yr	348.6 ton/yr
VOC:	6.1 lb/hr	2.6 lb/hr	22.1 ton/yr	11.6 ton/yr	76.9 ton/yr	76.9 ton/yr	230.7 ton/yr
PM10/PM2.5:	18.04 lb/hr	11.89 lb/hr	70.5 ton/yr	52.1 ton/yr	59.4 ton/yr	70.5 ton/yr	211.5 ton/yr
SO2:	0.98 lb/hr	0.84 lb/hr	4.1 ton/yr	3.7 ton/yr	3.3 ton/yr	4.1 ton/yr	12.3 ton/yr
H2SO4:	0.88 lb/hr	0.40 lb/hr	3.2 ton/yr	1.7 ton/yr	<3.2 ton/yr	3.2 ton/yr	9.5 ton/yr
NH3:	23.4 lb/hr	20.0 lb/hr	97.8 ton/yr	87.8 ton/yr	<97.8 ton/yr	97.8 ton/yr	293.5 ton/yr
Lead:	0.0017 lb/hr	0.0015 lb/hr	0.007 ton/yr	0.006 ton/yr	<0.007 ton/yr	0.007 ton/yr	0.022 ton/yr

Notes:

Duct burner capacity estimated at 500 MMBtu/hr (at 100% load).

Hourly emission estimates are based on worst-case ambient conditions (i.e., temperature, % relative humidity) at normal operations.

For lead, emission rates for natural gas firing are based on the worst-case firing rate, a heat content value of 1020 Btu/scf and the AP-42 emission factor of 0.0005 lb/MMcf.

For "Annual emissions with DB Firing at Operating Hour Limit", emission estimates were calculated as follows:

Annual Emissions (ton/yr) = [Pollutant Emission Rate, CT w/DB (lb/hr) x Operating Hours, CT w/DB (hr/yr) + Pollutant Emission Rate, CT only (lb/hr) x Operating Hours, CT only (hr/yr)] / (2000 lb / ton)

For "annual emissions with no DB firing", emission estimates for the natural gas firing (CT only) were based on 8760 operating hours per year.

ATTACHMENT B:

Toxic Pollutant Evaluation

Table B-5-1 Hazardous Air Pollutant Air Toxics Analysis- Mitsubishi M501GAC

Pollutant	Total - New Sources (Table B-5) Emission Rate, Total		Virginia Air Toxics Exemption Levels		Exempt? (hourly)	Exempt? (annual)	SAAC (ug/m3)	
	Maximum Hourly (lb/hr)	Annual (tpy)	Maximum Hourly (lb/hr)	Annual (tpy)	Yes/No	Yes/No	Hourly	Annual
1,3-Butadiene	2.79E-03	1.19E-02	1.452	3.19	Yes	Yes		
2-Methylnaphthalene	2.80E-05	8.86E-05	*	*	Yes	Yes		
3-Methylchloranthrene	2.10E-06	6.64E-06	*	*	Yes	Yes		
7,12-Dimethylbenz(a)anthracene	1.87E-05	5.90E-05	*	*	Yes	Yes		
Acenaphthene	8.45E-05	2.72E-05	*	*	Yes	Yes		
Acenaphthylene	1.70E-04	4.86E-05	*	*	Yes	Yes		
Acetaldehyde	2.54E-01	1.10E+00	8.91	26.1	Yes	Yes		
Acrolein	4.06E-02	1.76E-01	0.02277	0.03335	No	No	17.25	0.46
Anthracene	2.79E-05	1.51E-05	*	*	Yes	Yes		
Benz(a)anthracene	1.65E-05	1.02E-05	*	*	Yes	Yes		
Benzene	9.32E-02	3.42E-01	2.112	4.64	Yes	Yes		
Benzo(a)pyrene	6.18E-06	5.62E-06	*	*	Yes	Yes		
Benzo(b)flouoranthene	2.11E-05	1.14E-05	*	*	Yes	Yes		
Benzo(g,h,i)perylene	1.08E-05	6.78E-06	*	*	Yes	Yes		
Benzo(k)fluoranthene	6.14E-06	7.65E-06	*	*	Yes	Yes		
Chrysene	2.88E-05	1.33E-05	*	*	Yes	Yes		
Dibenzo(a,h)anthracene	8.59E-06	6.23E-06	*	*	Yes	Yes		
Dichlorobenzene	1.40E-03	4.43E-03	21.813	65.395	Yes	Yes		
Ethylbenzene	2.01E-01	8.82E-01	17.919	62.93	Yes	Yes		
Fluoranthene	8.91E-05	3.25E-05	*	*	Yes	Yes		
Fluorene	2.87E-04	8.12E-05	*	*	Yes	Yes		
Formaldehyde	1.46E+00	6.34E+00	0.0825	0.174	No	No	62.5	2.4
Hexane	2.10E+00	6.64E+00	11.616	25.52	Yes	Yes		
Indeno(1,2,3-cd)pyrene	9.96E-06	8.61E-06	*	*	Yes	Yes		
Naphthalene	1.13E-02	3.87E-02	2.607	7.54	Yes	Yes		
PAHs	1.38E-02	6.06E-02	*	*	Yes	Yes		
Phenanathrene	7.77E-04	2.52E-04	*	*	Yes	Yes		
Propylene Oxide	1.82E-01	7.99E-01	3.168	6.96	Yes	Yes		
Pyrene	7.95E-05	3.69E-05	*	*	Yes	Yes		
Toluene	8.27E-01	3.60E+00	18.645	54.665	Yes	Yes		
Xylene	4.07E-01	1.76E+00	21.483	62.93	Yes	Yes		
Arsenic	2.08E-03	1.00E-03	0.0132	0.029	Yes	Yes		
Beryllium	1.25E-04	6.02E-05	0.000132	0.00029	Yes	Yes		
Cadmium	1.15E-02	5.51E-03	0.0033	0.00725	No	Yes	2.5	
Chromium	1.46E-02	7.02E-03	0.0033	0.00725	No	Yes	2.5	
Cobalt	8.75E-04	4.21E-04	0.0033	0.00725	Yes	Yes		
Lead	5.21E-03	2.51E-03	0.0099	0.02175	Yes	Yes		
Manganese	3.96E-03	1.91E-03	0.33	0.725	Yes	Yes		
Mercury	2.71E-03	1.30E-03	0.0033	0.00725	Yes	Yes		
Nickel	2.19E-02	1.05E-02	0.0066	0.0145	No	Yes	5	
Selenium	2.50E-04	1.20E-04	0.0132	0.029	Yes	Yes		

Notes:
* Indicates that the neither exemption levels or SAACs exist.

DEQ VALLEY
APR 2 7 2010
To:
Date:

ATTACHMENT C:

DEQ Air Quality Modeling Analysis Memorandum

MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY
Office of Air Data Analysis and Planning

629 East Main Street, Richmond, VA 23219
8th Floor **804/698-4000**

To: Janardan Pandey, Air Permit Manager (VRO)

From: Mike Kiss, Coordinator - Air Quality Assessments Group (AQAG)

Date: October 4, 2010

Subject: Virginia Department of Environmental Quality (DEQ) Technical Review of the Air Quality Analyses in Support of the PSD Permit Application for the Proposed Dominion Natural Gas-Fired Power Plant in Warren County, Virginia (Warren County Power Station)

Copies: Tamera Thompson, Bobby Lute

I. Project Background

Virginia Electric and Power Company, a subsidiary of Dominion Resources, Inc. (Dominion), has proposed to construct and operate a 1280 megawatt (MW) natural gas-fired combined-cycle electric generating facility in the Warren Industrial Park, approximately one mile north of Interstate Route 66, in Warren County, Virginia. The proposed new facility, called the Warren County Power Station, will consist of three identical natural gas-fired only turbines, each with its own duct-fired heat recovery steam generator (HRSG), one reheat condensing steam turbine generator, three inlet turbine chillers, a natural gas-fired only auxiliary boiler, a diesel-fired emergency generator and fire water pump engine, and a natural gas-fired only fuel heater. Dominion has proposed to install Mitsubishi (M501 GAC) turbines.

The proposed facility meets the definition of major source under 9 VAC 5 Chapter 80, Article 8 (Prevention of Significant Deterioration (PSD)) of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution because it is a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr heat input capacity and has the potential to emit 100 tons per year or more of a regulated pollutant. The pollutants subject to PSD review are nitrogen oxides (NO_X), particulate matter having an aerodynamic diameter equal to or less than 10 microns (PM_{10}), particulate matter having an aerodynamic diameter equal to or less than 2.5 microns ($PM_{2.5}$), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid mist. As a result, PSD regulations require an air quality analysis be performed that demonstrates that the projected air emissions from the proposed facility will neither cause or significantly contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. In addition, PSD regulations require that an additional impact analysis consisting of a soil and vegetation analysis, a growth analysis and a visibility impairment analysis be conducted. An analysis of the project's impact on air quality and air quality related values (AQRVs) in any affected Class I area is also required. The AQRV analysis is subject to review by the AQAG and the appropriate Federal Land Manager (FLM).

The following is a summary of the AQAG's review of the required air quality analyses for the Warren County Power Station for both Class I and Class II PSD areas. The worst-case impacts from all operating loads, including startup and shutdown operations, are presented in this memorandum.

The Class I and Class II air quality analyses received by the AQAG were dated July 2 and 14, 2010. Supplemental analyses received by the AQAG were dated August 27, 2010 and September 2, 2010.

II. Modeling Methodology

The Class I and Class II air quality modeling analyses conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and were performed in accordance with their respective approved modeling methodology that were included in a protocol that was submitted in advance by the proposed facility. DEQ approved the protocol on March 23, 2010. The FLMs were provided an opportunity to comment on the Class I area modeling methodology. The United States Forest Service (USFS) provided comments in an e-mail dated February 4. 2010. The USFS concluded, based on the emission rates in the protocol and distances to the Class I areas, that *"modeling would not show any significant additional impacts to air quality related values (AQRV) at the Class I areas administered by the US Forest Service."* Therefore, the USFS did not request that a Class I AQRV analysis be included in the PSD permit application. The National Park Service (NPS) FLM provided comments and approved the modeling protocol in an e-mail dated April 1, 2010. The NPS issues were also discussed and agreed upon during a conference call on April 19, 2010.

The air quality model used for both Class I and Class II area analyses was the most recent version of the AERMOD modeling system (Version 09292). The AERMOD modeling system is the preferred EPA-approved regulatory model for near-field applications and is contained in Appendix W of 40 CFR Part 51. The PLUVUE II model (Version 96170) was also used to assess plume impairment in Shenandoah National Park. This model is approved by the FLMs for evaluating plume impairment (i.e., near-field visibility impacts) in Class I areas.

III. Modeling Results

A. Class II Area - Preliminary Modeling Analysis

A preliminary modeling analysis for criteria pollutants was conducted in accordance with PSD regulations to predict the maximum ambient air impacts. The preliminary analysis modeled emissions from the proposed facility only to determine whether or not the impacts were above the applicable significant impact levels (SILs). For those pollutants for which maximum predicted impacts were less than the SIL, no further analyses was required (i.e., predicted maximum impacts less than SILs are considered insignificant and of no further concern). For impacts predicted to be equal to or greater than the SIL, a more refined air quality modeling analysis (i.e., full impact or cumulative impact analysis) is required to assess compliance with the NAAQS and PSD increment.

The emissions associated with four (4) representative operating loads were modeled, as well as startup/shutdown emissions. Attachment A contains the specific emission rates and corresponding stack parameters that were modeled. Table 1 below shows the maximum predicted ambient air concentrations.

Table 1
Class II Preliminary Modeling Analysis Results vs. Significant Impact Levels

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility ($\mu g/m^3$)	Class II Significant Impact Level ($\mu g/m^3$)
NO_2	1-Hour	N/A[1]	7.5
	Annual	0.60	1
PM_{10}	24-hour	6.74	5
	Annual	0.43	1
$PM_{2.5}$	24-hour	6.74	1.2
	Annual	0.41	0.3
CO	1-hour	869.70	2,000
	8-hour	139.21	500

(1) SIL modeling not conducted for 1-hour NO_2. Worst-case assumption was used (i.e., project emissions are significant out to the valid range of the model (i.e., 50 km)).

The modeling results for NO_2 (annual averaging period), PM_{10} (annual averaging period), and CO (1-hour and 8-hour averaging periods) were less than the applicable SILs. Therefore, a full impact analysis for these pollutants and averaging periods was not required. However, a full impact analysis for NO_2 (1-hour averaging period), PM_{10} (24-hour averaging period), and $PM_{2.5}$ (24-hour and annual averaging periods) was conducted because the preliminary modeling analysis results exceeded the applicable SILs.

The AQAG has adopted the NO_2 (1-hour) SIL in Table 1 based on a review of the following documentation:

Guidance Concerning the Implementation of the 1-hour NO2 NAAQS for the Prevention of Significant Deterioration Program, Stephen D. Page, EPA, June 29, 2010.

The staff concurs with the EPA recommendations in this memorandum that it is appropriate to derive an interim 1-hour NO_2 SIL by using an impact equal to 4% of the 1-hour NO_2 NAAQS (4 ppb is equivalent to 7.5 $\mu g/m^3$). The AQAG believes that it is reasonable to adopt this value based on consideration of the impact level relative to the NAAQS and past EPA rationale for existing short-term averaging period SILs. The use of 4% of the NAAQS as a threshold is also consistent with previous EPA rulemaking and supporting documentation as described in the June 29, 2010 EPA memorandum.

The AQAG has adopted the $PM_{2.5}$ (24-hour and annual) SILs in Table 1 based on a review of the following documentation:

Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5)-Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Proposed Rule, 40 CFR Parts 51 and 52, September 21, 2007.

The AQAG determined that EPA's Option 3 on Page 54115 of the Federal Register was appropriate as an interim value based on (1) the fact that these values are the most stringent option proposed by EPA, (2) it uses the existing PM_{10} SIL to PM_{10} NAAQS ratio as a basis for its derivation, and (3) staff has verbal confirmation from EPA that the final SIL will be selected from one of the proposed options. It should be noted that air quality impacts resulting from direct (primary) PM_{10} and $PM_{2.5}$ emissions can often be correlated. In fact, direct PM_{10} and $PM_{2.5}$ emissions from a natural gas-fired combined-cycle electric generating facility are usually identical for all practical purposes.

B. Class II Area – Cumulative Impact Modeling Analysis

The cumulative impact analysis described below consisted of separate analyses to assess compliance with the NAAQS for NO_2, PM_{10}, and $PM_{2.5}$ and the PSD increment for PM_{10} for the indicated averaging periods. No PSD increment analyses were required for NO_2 (1-hour averaging period) and $PM_{2.5}$ (24-hour and annual averaging periods) because EPA has not yet promulgated Class II PSD increments for these pollutants and averaging periods.

It is important to note that the cumulative impact modeling results (both NAAQS and PSD increment) can sometimes be less than the "source only" modeling results in Table 1 of this memorandum. This is due to the fact that source only modeling uses the maximum concentration to determine significance, whereas the cumulative modeling results reflect the form of the air quality standard. For example, the following criteria must be met to attain the NAAQS:

- CO (1-hour and 8-hour) - Not to be exceeded more than once per year
- NO_2 (1-hour) - To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed the standard
- NO_2 (annual) - Never to exceed the standard
- PM_{10} (24-hour) - Not to be exceeded more than once per year on average over 3 years
- $PM_{2.5}$ (24-hour) - To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed the standard
- $PM_{2.5}$ (annual) - To attain this standard, the 3-year average of the weighted annual mean $PM_{2.5}$ concentrations from single or multiple community-oriented monitors must not exceed the standard

NAAQS Analysis

The NAAQS analysis included emissions from the proposed source, emissions from existing sources from Virginia, West Virginia, and Maryland and representative ambient background concentrations of NO_2, PM_{10}, and $PM_{2.5}$. The results of the analysis are presented in Table 2 and demonstrate compliance with the applicable NAAQS.

Table 2
NAAQS Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	109.07	7.97[1]	75.2	184.27	188
PM_{10}	24-hour	4.98	4.92	34.7	39.68	150
$PM_{2.5}$	24-hour	4.38	4.23	28.0	32.38	35
	Annual	0.48	0.38	11.7	12.18	15

(1) The project contribution provided represents the highest single year's concentration that significantly contributes to the Total Concentration.

PSD Increment Analysis

The 24-hour PM_{10} PSD increment analysis included emissions from the proposed source and emissions from increment-consuming sources from Virginia, West Virginia, and Maryland. Table 3 below presents the results of the analysis and shows that the 24-hour PM_{10} concentration was below the PSD increment.

Table 3
PSD Increment Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
PM_{10}	24-hour	4.98	4.92	30

NAAQS and PSD Increment Analyses Conclusions

Based on DEQ's review of the NAAQS and PSD increment analyses, the proposed Warren County Power Station does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment.

Toxics Analysis

The source is subject to the state toxics regulations at 9 VAC 5-60-300 et al. An analysis was conducted in accordance with the regulations and the predicted concentrations for each toxic pollutant were below their respective Significant Ambient Air Concentrations (SAAC). Table 4 summarizes the toxic pollutant modeling analysis results.

Table 4
Toxics Analysis Maximum Predicted Concentrations

Toxic Pollutant	Averaging Period	Maximum Modeled Concentration From Project ($\mu g/m^3$)	SAAC ($\mu g/m^3$)
Acrolein	1-hour	4.36E-02	17.25
	Annual	2.30E-04	0.46
Formaldehyde	1-hour	1.58E+00	62.5
	Annual	9.24E-03	2.4
Cadmium	1-hour	1.23E-02	2.5
Chromium	1-hour	1.56E-02	2.5
Nickel	1-hour	2.34E-02	5

Additional Impact Analysis

In accordance with the PSD regulations, additional impact analyses were performed to assess the impacts from the proposed facility on visibility, vegetation and soils, and the potential for and impact of secondary growth. These analyses are discussed below.

Visibility

A screening modeling analysis was conducted to assess the potential for visual plume impacts in Class II areas within 50 kilometers (km) of the project site. A review of National Parks in Virginia indicated that the Appalachian Trail is the closest identified potentially sensitive area outside Shenandoah National Park. The project site is about 11 km northwest of the nearest approach of the Appalachian Trail.

The visibility screening modeling approach followed guidance provided in EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised) (October 1992; EPA-454/R-92-023)*. The two visibility metrics that were evaluated in the VISCREEN modeling analysis are:

- **Plume contrast (|C|)**: Contrast can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object (e.g., plume) and its background (e.g., sky). Plume contrast results from an increase or decrease in light transmitted from the viewing background through the plume to the observer.

- **Plume perceptibility (ΔE)**: A parameter used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background such as the sky, a cloud, or a terrain feature.

The VISCREEN results were developed for startup/shutdown and normal operating scenarios. All results were below the significance criteria in the nearest Class II National Park. Therefore, the plume is expected to be imperceptible against the background sky and the terrain. A Class I area visibility analysis was performed for Shenandoah National Park and is discussed in Section C of this memorandum.

The visibility in the area near the proposed facility will be protected by operational requirements, such as air pollution controls and clean burning fuels, and stringent limits on visible emissions that are incorporated into the draft permit.

Vegetation and Soils

An analysis on sensitive vegetation types with significant commercial or recreational value was conducted. The analysis compared maximum predicted concentrations from the proposed facility against a range of injury thresholds found in various peer-reviewed research articles as well as criteria contained in the EPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA, 1981).* Table 5 shows the maximum predicted concentrations for NO_2, PM_{10}, and CO were all below the respective thresholds (i.e., the minimum reported levels at which damage or growth effects to vegetation may occur). As a result, no adverse impacts on vegetation are expected.

Table 5
Comparison of Vegetation Sensitivity Thresholds to Maximum Modeled Concentrations from the Warren County Power Station

Pollutant	Averaging Period	Maximum Modeled Concentration From Proposed Facility ($\mu g/m^3$)	Sensitive Vegetation Threshold ($\mu g/m^3$)
NO_2	1-hour	342.97[1]	940
	4-hour	73.56	3,760
	1-month	1.12	564
	Annual	0.60	94
PM_{10}	24-hour	6.74	150
	Annual	0.43	50
CO	1-week	7.65	1,800,000

(1) Please note the 1-hour NO_2 concentration is the highest modeled concentration over the 5 modeled years. This is not consistent with how the new 1-hour NO_2 NAAQS is defined.

The impact of the emissions on soils in the vicinity of the proposed project was evaluated. The soil type was determined from data collected from the United States Department of Agriculture's Natural Resources Conservation Service (NRCS) Soil Survey Geographic (SSGUGO) database and the NRCS Web Soil Survey tool. The soil types within the nearby counties of Warren, Clarke, Frederick, and Shenandoah are similar in composition.

The predominant soil types in Warren County are silt and stony loams. In Clarke County, the predominate soil types are silt and sandy loams with rocky outcrops. Frederick County contains a mixture of silt and gravely/cobbly loams with some areas of fine sandy loams. In Shenandoah County, the soil types are also a mixture of silt, clay, and cobbly and sandy loams.

The soil types in the adjacent counties are generally considered to have a moderate to high buffering capacity and have a higher capacity to absorb acidic deposition without changing the soil pH. Based on the soil types and quantity of emissions from the proposed project, no adverse impact on local soils is anticipated.

A discussion of the impacts of acidic deposition in Shenandoah National Park is provided in Section C of this memorandum.

Growth

The work force for the proposed facility is expected to range from 400 to 600 jobs during various phases of the construction. It is expected that a significant regional construction force is already available to build the proposed facility. Therefore, it is anticipated that no new housing, commercial or industrial construction is necessary to support the Warren County Power Station during the two-year construction schedule. The proposed facility will also require approximately 20 to 25 permanent positions. It is assumed that individuals that already live in the region will perform a number of these jobs. No new housing requirements are expected for any new personnel moving to the area. In addition, due to the small number of new individuals expected to move into the area to support the Warren County Power Station and the existence of some commercial activity in the area, new commercial construction would not be necessary to support the permanent work force. Additionally, no significant level of industrial related support will be necessary for the Warren County Power Station. Therefore, industrial growth is not expected.

Based on the growth expectations discussed above, no new significant emissions from secondary growth during the construction and operation phases of the Warren County Power Station are anticipated.

C. Class I Area Modeling Analysis

The FLMs are provided reviewing authority of Class I areas that may be affected by emissions from a proposed source by the PSD regulations and are specifically charged with protecting the Air Quality Related Values (AQRV) within the Class I areas. The closest Class I area to the proposed facility is the Shenandoah National Park (SNP). Its nearest point is approximately 7.1 km from the project site. The next closest Class I area, Dolly Sods Wilderness Area in West Virginia, is approximately 100 km upwind (based on the prevailing wind direction) from the proposed facility.

Modeling guidance provided in 2008 by the Federal Land Managers' Air Quality Related Values Work Group (FLAG), provides screening criteria for determining whether a source may be excluded from performing a Class I area AQRV modeling analysis. The FLMs may consider excluding a source from modeling if its total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions) divided by the distance (in km) from the Class I area is less than or equal to 10. The sum of the emissions for the proposed project is not expected to exceed approximately 600 tons per year (tpy). Therefore, the FLAG 2008 screening distance for the SNP is 84.5 (600 tpy/7.1 km). The screening distance for all other Class I areas is less than 6 (600 tpy/100 km or greater). Based on the FLM screening criteria, an AQRV analysis was conducted for the SNP. The USFS did not require an analysis of the more distant Class I areas (Dolly Sods Wilderness Area, Otter Creek Wilderness Area, and James River Face Wilderness Area).

A preliminary modeling analysis for NO_2, PM_{10}, and $PM_{2.5}$ was conducted to determine whether or not the predicted maximum ambient air impacts in the SNP were above the Class I SILs. CO emissions were not modeled because the maximum ambient air impacts for the Class II area were well below the applicable Class II SILs (see Table 1 for details) and there is no Class I area SIL for this pollutant. The emissions used in the Class I area modeling were the same as those used for the Class II area modeling. A more refined air quality modeling analysis (i.e., cumulative impact analysis) was required to assess compliance with the NAAQS and Class I PSD increments for impacts predicted to be equal to or above the Class I SIL. No additional air quality analysis was required for pollutants when the proposed project's impacts were less than the SIL.

The proposed facility's maximum predicted ambient air concentrations for NO_2, PM_{10}, and $PM_{2.5}$ in the SNP are presented in Table 6. The predicted concentrations for all pollutants were above all of the applicable Class I SILs in the SNP. Therefore, a cumulative impact analysis was required for these pollutants. It is important to note that no analysis was required for demonstrating compliance with the annual PM_{10} NAAQS because the standard was revoked by EPA in 2006. Additionally, no Class I PSD increment analysis for $PM_{2.5}$ and 1-hour NO_2 was required because EPA has not yet promulgated these Class I PSD increments.

Table 6
Summary of Maximum Predicted Concentrations from the Proposed Facility for Shenandoah National Park

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility ($\mu g/m^3$)	Class I Significant Impact Level ($\mu g/m^3$)
NO_2	1-hour	N/A(1)	7.5
	Annual	0.27	0.1
PM_{10}	24-hour	5.55	0.3
	Annual	0.21	0.2
$PM_{2.5}$	24-hour	5.55	0.07
	Annual	0.21	0.06

(1) SIL modeling not conducted for 1-hour NO_2. Worst-case assumption was used (i.e., project emissions are significant out to the valid range of the model (i.e., 50 km)).

NAAQS Analysis

The NAAQS analysis for SNP included emissions from the proposed source, emissions from existing sources from Virginia and West Virginia, and representative ambient background concentrations of NO_2, PM_{10}, and $PM_{2.5}$. The results of the analysis are presented in Table 7 and demonstrate compliance with the NO_2, PM_{10}, and $PM_{2.5}$ NAAQS. Please note that the 1-hour NO_2 receptor grid did not differentiate between Class I and Class II receptors. Therefore, the NO_2 concentration presented in the table below is the highest design value for both Class I and Class II areas (i.e., the same value as presented in Table 2).

Table 7
NAAQS Modeling - Cumulative Impact Results for Shenandoah National Park

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	109.07	7.97[1]	75.2	184.27	188
	Annual	0.45	0.27	12.5	12.95	100
PM_{10}	24-hour	5.15	5.10	34.7	39.85	150
$PM_{2.5}$	24-hour	3.74	3.72	28.0	31.74	35
	Annual	0.13	0.11	11.7	11.83	15

(1) The project contribution provided represents the highest single year's concentration that significantly contributes to the Total Concentration.

PSD Increment Analysis

The PSD increment analysis included emissions from the proposed source and emissions from increment-consuming sources from Virginia and West Virginia. Table 8 presents the results of the PSD increment analysis. All predicted impacts are less than the applicable PSD increments.

Table 8
PSD Increment Modeling - Cumulative Impact Results for Shenandoah National Park

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
NO_2	Annual	0.45	0.27	2.5
PM_{10}	24-hour	5.15	5.10	8
	Annual	0.27	0.21	4

Air Quality Related Values

An AQRV analysis (acidic deposition and visibility) was performed for the Class I area (i.e., SNP) and is discussed in the sections below.

Acidic Deposition

An analysis of the potential sulfur (S) and nitrogen (N) deposition at the SNP was conducted in accordance with guidance from the FLM. The FLM approved the protocol on April 19, 2010. The results of the analysis were compared to the sulfur and nitrogen deposition analysis threshold (DAT) of 0.010 kilograms per hectare per year (kg/ha/yr) for eastern Class I areas. The DAT is defined as the additional amount of sulfur or nitrogen deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The DAT is a deposition threshold, not necessarily an adverse impact threshold. If the additional amount of deposition is greater than or equal to the DAT, further analysis is usually required by DEQ and the FLM.

Table 9 presents a summary of the maximum predicted sulfur and nitrogen deposition rates for the SNP. The maximum predicted sulfur deposition rate was below the DAT and the maximum predicted nitrogen deposition rate was above the DAT. Two models were run to obtain these results. AERMOD was run in accordance with the approved modeling protocol. CALPUFF was run by the DEQ, FLM, and the applicant to provide supplemental information on nitrogen deposition.

Table 9
Maximum Predicted Annual Sulfur and Nitrogen Deposition Rates from the Proposed Facility for Shenandoah National Park

AERMOD Sulfur Deposition (kg N/ha/yr)	Deposition Analysis Threshold for S (kg N/ha/yr)	AERMOD Nitrogen Deposition (kg S/ha/yr)	CALPUFF Nitrogen Deposition (kg S/ha/yr)	Deposition Analysis Threshold for N (kg S/ha/yr)
0.008	0.010	0.04	0.022	0.010

The applicant provided documentation which discusses the impact of the additional nitrogen deposition on the SNP (see Section 8.6 of the applicant's report). Part of that documentation included a study of acidic deposition in the SNP that was published by the NPS in 2006.

Cosby, B.J., J.R. Webb, J.N. Galloway, and F. A. Deviney, 2006. Acidic Deposition Impacts on Natural Resources in Shenandoah National Park. Technical Report NPS/NER/NRTR—2006/066. Available at <u>http://www.nps.gov/nero/science/FINAL/SHEN_acid_dep/SHEN_acid_dep.htm</u>

The following conclusions could be made based on a review of the 2006 report:

- The 2006 NPS study indicates that the northern portion of SNP where the modeled nitrogen deposition exceeds the DAT may be less sensitive to acidic deposition than the central and southern portions of the park where the DAT is not exceeded for this project.
- The 2006 NPS study indicates that there is a "low concern" for acidification effects on streams and soils in the area of SNP within 14 km of the project site. Beyond 14 km, there is a "moderate concern" for acidification effects. The peak nitrogen deposition impact occurs at a downwind distance of approximately 9 kilometers and falls below the DAT beyond 14 km. Therefore, estimated impacts of acidic deposition beyond 14 km are considered insignificant.

Despite the conclusions based on the 2006 NPS study, DEQ had previously identified Jeremy's Run, a watershed that is partially contained within the northern end of the SNP, as an impaired stream for pH (Atmospheric Deposition – Acidity). This classification is present in the most recently approved DEQ Water Quality Assessment (2008). The classification has also been carried forward in the draft 2010 DEQ Water Quality Assessment that has not yet been approved by the State Water Control Board.

Jeremy's Run is listed as impaired for pH based on data collected by the United States Geological Survey (USGS) (Site 01630565) in 2001 and 2002. The listing is based on two violations of pH out of 2 samples taken. The stream was originally listed in the 303(d) list (i.e., Clean Water Act list of impaired waters) in the 2004 assessment cycle. The USGS data from this site is as follows:

- Sample taken on 8/21/01 at 17:30 hrs with a value of 6.1
- Sample taken on 7/8/02 at 14:00 hrs with a value of 6.0

The pH special standard that currently applies to Jeremy's Run is 6.5-9.5 and is based on the assumption of limestone substrate in the western portion of Virginia in the Shenandoah Valley. This site is located in the uppermost headwaters of Jeremy's Run where the substrate is not limestone. Therefore, areas such as Jeremy's Run and other locations on top of the mountains (i.e., both the western and eastern slopes of the SNP) do not fit this description. It should be noted that the USFS had a number of their streams reclassified in the last triennial review of water quality standards to have the statewide pH standard of 6-9 apply.

More recent data, although not certified by DEQ, suggests that stream acidification in the SNP continues to be a concern. For example, the Shenandoah Watershed Study (SWAS) program conducts watershed research and monitoring in the Shenandoah National Park as well as other areas. The SWAS program studies acidic deposition in sensitive streams, most of which support reproducing populations of the native brook trout. The SWAS program concluded that stream water acidification is a continuing problem in Virginia's forested mountain watersheds. A link to the SWAS program is provided below:

http://swas.evsc.virginia.edu/

Both the FLM and DEQ have expressed concern over acidic deposition potential in the SNP. As a result, DEQ has inserted a plan into the permit (Condition 23) for the purposes of mitigating potential air quality impacts on acidic deposition. The proposed mitigation plan in the draft permit requires reduction and/or mitigation of nitrogen oxides emissions from the facility. Reduction and/or mitigation may consist of Dominion purchasing nitrogen oxides emission offsets allowances or obtaining reductions from one or more facilities in a specified geographic area. DEQ is soliciting public comment on the Class I Area mitigation plan.

At this time, the FLM has not issued any formal finding of adverse impact on the SNP. The FLM is provided 60 days to review and comment on the proposed PSD permit. The 60-day review period started on September 7, 2010. DEQ will review additional documentation provided by the FLM during the comment period and make any necessary revisions to the permit if warranted. DEQ has continued its dialogue with the FLM throughout the permitting and modeling process to ensure that any concerns are addressed.

Visibility

Plume visibility impacts inside the SNP within 50 km were evaluated using the PLUVUE II model. This approach is preferred by the FLMs and is consistent with past modeling exercises (i.e., previous permitting of the Competitive Power Ventures (CPV) project at the same site).

Several viewpoints within the Class I area were selected by the NPS for the plume visibility analysis. These are as follows:

- **Shenandoah Valley Overlook**: located about 9 km from the proposed project site, it offers views to the north toward Front Royal.

- **Dickey Ridge**: located about 11 km from the proposed project site, it offers views to the northeast within the Park and views to the southeast and southwest toward terrain within the Park.

- **Signal Knob Overlook**: located about 12.5 km from the proposed project site, it offers fairly long views to the south, southwest, and southeast within Park boundaries. In addition, there is a view toward the west to areas beyond Park boundaries.

- **Compton Gap Road**: selected as a supplemental viewpoint by the NPS due to its location at the highest point along Compton Gap Road, about 14.6 km from the project site. It offers long views of Park terrain toward the southwest and shorter views toward the west and northwest.

- **Lands Run Road Gate**: selected as a supplemental viewpoint by the NPS for its location where Lands Run Road crosses the western boundary of the Park. It is approximately 16.5 km from the proposed project site and it offers long views to the south and southwest, although viewing distances to the east are limited by elevated terrain.

As with the Class II visibility modeling, the two metrics that were evaluated in the PLUVUE II modeling were plume contrast (|C|) and plume perceptibility (ΔE). There were two approaches used to calculate plume impairment:

- **FLAG Approach**: PLUVUE II was run for each hour identified from the 5-year meteorological period for meteorological conditions associated with the Class I Levels of Concern (an absolute value of at least 0.02 for |C| and 1.0 for ΔE). The results of the PLUVUE II analyses were summarized for each viewpoint and the probability of potential future occurrences during peak project emission periods were calculated by reviewing the frequency of hours determined to be above perceptible visibility thresholds, especially during periods of peak park visitation.

- **Refined Approach**: A refined plume impairment analysis was conducted to account for effects on plume perceptibility due to the apparent plume width. As noted by Richards et al. (2007),

  > *"In the real world, plumes are viewed against a background of sky or terrain that does not have a uniform luminance and color, even when there are no clouds. For faint plumes, the effect of a plume is to introduce a small distortion in the luminance and color profile of the background. As the angle subtended by a plume increases (i.e., the plume fills a larger portion of the observers total field of view), the plume is spread over a larger change in the luminance and color of the background sky. For a given value of the plume contrast or color difference, the changes in luminance and color attributable to the plume become a smaller fraction of the naturally occurring variations in the luminance and color of the background sky. Thus, it is reasonable to believe that the adjustment needed to convert laboratory contrast thresholds into thresholds appropriate for the real world increases as the plume subtended angle increases."*

  The procedures for implementing an adjustment to |C| and ΔE are described by Richards et al. (2007) as well as Zell et al. (2007). This involves computation of the plume angle subtended for each line of sight and simulated PLUVUE hour, computing appropriate threshold values for |C| and ΔE, and then comparing the modeled plume parameter to this threshold.

The following are observations based on a review of the plume impairment analysis:

- Signal Knob Overlook has the greatest number of excursion hours.
- Shenandoah Valley Overlook has the fewest number of excursion hours.
- At no viewpoint would excursion hours occur more than approximately 0.5% of the daytime hours over the 5-year modeled period using the FLAG approach.
- The refined approach indicates that a plume is likely to be perceptible less than 0.15% of the time at Signal Knob Overlook and at a much smaller percentage of the time at other viewpoints.
- |C| and ΔE for terrain background, as opposed to sky, account for the vast majority of the excursions. This indicates that an elevated plume viewed against the background sky would seldom be visible.
- The degree to which a plume could be visible against actual terrain of various colors is likely to be overestimated because the model simulates terrain with uniform reflectivity (grey, white or black).
- Both the plume visibility assessment using the more conservative FLAG perceptibility thresholds and the refined approach thresholds indicate that the modeled frequency of visible plumes associated with the project will be well less than one percent, the significance threshold established in the *Workbook for Plume Visual Impact Screening and Analysis (EPA, 1992)*.

The intensity, geographic extent, duration, frequency and timing of these plume impairment events do not appear to reach the threshold of an adverse impact in the SNP. However, the FLM has not established a "bright line" for determining an adverse impact based on plume impairment. The FLM is provided 60 days to review and comment on the proposed PSD permit. DEQ will review additional documentation provided by the FLM during the comment period and make any necessary revisions to these findings if warranted.

The detailed visibility impairment results are provided in Attachment B. The results are summarized for each viewpoint and the probability of potential future occurrences during peak project emission periods are calculated by reviewing the frequency of hours determined to be above perceptible visibility thresholds.

Summary of Class I Area Analysis

Based on DEQ's review of the modeling analyses, the proposed Warren County Power Station does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class I area PSD increment. The impact of the project's emissions on acidic deposition in the SNP is a concern for both DEQ and the FLM. The permit contains a draft Class I Area mitigation plan that is available for public review and comment.

The PSD regulations provide reviewing authority to the FLM. The 60-day FLM review period began on September 7, 2010. In accordance with 9 VAC 5-80-1765 D, the FLM has an opportunity to notify DEQ of any adverse impact on the AQRVs. The FLM's authority to make a determination of an adverse impact on the AQRVs is invoked most frequently in the context of the preconstruction permit review procedure specified in Section 165 of the Clean Air Act. In the event that any adverse impact comments are received, DEQ will address the new information and revise this analysis if warranted.

D. Other Modeling Considerations

Facilities Locating within 10 Kilometers (km) of a Class I Area

PSD regulations require that modeling should be performed for any emissions rate at a new PSD major stationary source or net emissions increase associated with a modification at an existing PSD major stationary source located within 10 kilometers (km) of a federal Class I area to determine if the maximum 24-hour average impact of the regulated pollutant in the Class I area is equal to or greater than 1.0 micrograms per cubic meter ($\mu g/m^3$) on a 24-hour basis. If the 24-hour impact is equal to or greater than 1.0 $\mu g/m^3$, the emissions rate associated with the new major stationary source or the net emissions increase associated with a modification at an existing major stationary source is considered significant and the regulated pollutant would be subject to PSD review.

The proposed facility will be located approximately 7.1 km from SNP. Therefore, all regulated pollutants to be emitted from the proposed facility that were not initially identified as subject to PSD review based on their annual emission rate (i.e., tons per year) were evaluated. The maximum 24-hour average impacts for all other regulated pollutants are less than 1.0 $\mu g/m^3$ and are not subject to PSD review.

Ozone

Warren County is currently designated attainment for ozone based on the 1997 standard (0.08 parts per million (ppm)) and the 2008 standard (0.075 ppm). The 2008 standard is currently being reconsidered by EPA. Specifically, on January 6, 2010, EPA proposed to strengthen the NAAQS for ground-level ozone, the main component of smog. The proposed revisions are based on scientific evidence about ozone and its effects on people and the environment. EPA is proposing to strengthen the 8-hour "primary" ozone standard, designed to protect public health, to a level within the range of 0.060-0.070 ppm. EPA is also proposing to establish a distinct cumulative, seasonal "secondary" standard, designed to protect sensitive vegetation and ecosystems, including forests, parks, wildlife. At this point, the final outcome of this proposal is not known. The latest information at the time of public notice suggests that the new ozone standards may be finalized by the end of 2010.

The mitigation plan outlined in Condition 23 of the draft permit provides for NO_X emissions offsets or emissions reductions which are at least equivalent to those required in moderate ozone nonattainment area permitting (i.e., ratio of at least 1.15 to 1). The Best Available Control Technology (BACT) permit requirements are also at or near the Lowest Achievable Emission Rate (LAER) for the subject source as required in a nonattainment area.

VOC offsets are not required by current air regulations and are not contained in the permit. It is important to note that recent research demonstrates that rural regions and, in fact, most if not all of Virginia, are considered "NO_X limited" for the purposes of ozone formation. In other words, the concentration of ozone depends on the amount of NO_X in the atmosphere. This occurs when there is a lack of NO_2, thus inhibiting ozone titration when oxygen mixes with VOCs. In these regions, controlling NO_X would reduce ozone concentrations whereas controlling VOCs would have little if any effect on ozone formation.

Rural areas are usually NO_X limited due to the large amount of trees that produce relatively high concentrations of VOCs. For instance, the Blue Ridge Mountains are named in part because the high VOC levels reflect blue light. Regions that are "VOC limited" lack trees and are usually congested with high vehicular activity.

Attachment A

Emission Rates and Stack Parameters

Worst-Case Data for Proposed Natural Gas-Fired Combined-Cycle Combustion Turbine Operation

Parameter		Value[1]			
Load (%)		**100 w/ Duct Firing**	**100**	**75**	**60**
Stack Height (ft)		175.0	175.0	175.0	175.0
Stack Diameter (ft)		22.0	22.0	22.0	22.0
Exit Temperature (°F)		191.20	197.70	191.50	185.00
Exit Velocity (ft/sec)		57.83	57.74	48.32	41.16
Heat Input (MMBtu/hr)		3,496	2,996	2,302	1,966
Pollutant Emissions Per Combustion Turbine (lb/hr)	**SO_2**	(2)	(2)	(2)	(2)
	PM_{10} 24 hour	21.16	15.51	11.92	10.18
	PM_{10} Annual[3]	19.38	19.38	19.38	19.38
	$PM_{2.5}$ 24 Hour	21.16	15.51	11.92	10.18
	$PM_{2.5}$ Annual[3]	19.38	19.38	19.38	19.38
	NO_X Annual[3]	24.18	24.18	24.18	24.18
	CO	17.41	9.91	7.61	6.50

(1) The values in the table represent the worst-case stack parameters and the emission rates for the four operating loads.

(2) Emission estimates indicate that SO_2 was not subject to PSD review. Therefore, an SO_2 modeling analysis was not performed.

(3) Annual emissions based on the worst-case emissions across all normal operations or normal operating plus SUSD. The following worst-case annual emissions will be annualized and modeled across all operating loads:

- PM_{10} – 84.89 tpy / 8760*2000 = 19.38 lb/hr
- NO_X – 105.90 tpy / 8760*2000 = 24.18 lb/hr

Source Parameters and Criteria Pollutant Emission Rates[1] For the Auxiliary Equipment

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr) NOx	CO	PM_{10}	$PM_{2.5}$	SO_2
Inlet Turbine Chiller1[2]									
CHLR1	42.88	12.00	70.00	24.50	--	--	5.99E-03	1.84E-05	--
Inlet Turbine Chiller2[2]									
CHLR2	42.88	12.00	70.00	24.50	--	--	5.99E-03	1.84E-05	--
Inlet Turbine Chiller3[2]									
CHLR3	42.88	12.00	70.00	24.50	--	--	5.99E-03	1.84E-05	--
Auxiliary Boiler									
AUX_BLR	115.00	3.00	300.00	61.00	0.97	3.26	0.44	0.44	(3)
Fuel Gas Heater									
FGH	45.00	3.33	300.00	32.00	0.57	1.92	0.39	0.39	(3)

(1) Data provided by Dominion.
(2) The hourly emissions represent the emissions from a single cell of the 6-cell inlet turbine chiller.
(3) Emission estimates indicate that SO_2 was not subject to PSD review. Therefore, an SO_2 modeling analysis was not performed.

Source Parameters and Criteria Pollutant Emission Rates[1] For the Emergency Equipment

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr)[2] NOx	CO 1-hour	CO 8-hour	PM_{10} 24-hour	PM_{10} Annual	$PM_{2.5}$ 24-hour	$PM_{2.5}$ Annual	SO_2
Diesel-Fired Emergency Generator												
DSL_GEN	115.00	1.23	987.00	135.00	0.14	12.62	1.58	0.06	0.0086	0.06	0.0086	(3)
Diesel-Fired Fire Water Pump Engine												
FWP	20.00	0.44	845.00	135.00	0.012	1.72	0.22	0.0083	0.0012	0.0083	0.0012	(3)

(1) Data provided by Dominion.
(2) Emissions rates were normalized based on the following equations:
Short-term Averaging Period – Emission Rate * (1/ Hours of Averaging Period)
Annual Averaging Period – Emission Rate * 52 hours per year / 8,760
(3) Emission estimates indicate that SO_2 was not subject to PSD review. Therefore, an SO_2 modeling analysis was not performed.

Short-Term Averaging Period Startup Summary[1]

	Offline	Start	Normal	Total	Start	Normal	Total
	min	min	min	min	lb	lb	Lb
CO 1-hour							
Turbine 1	0	60	0	60	813.90	0	813.90
Turbine 2	60	0	0	60	0	0	0
Turbine 3	60	0	0	60	0	0	0
Startup Total							813.90
Normal Operation Total[2]							52.23
CO 8-hour							
Turbine 1	0	252	228	480	2205.30	66.16	2271.46
Turbine 2	252	101	127	480	804.20	36.85	841.05
Turbine 3	353	101	26	480	804.20	7.54	811.74
Startup Total							3924.25
Normal Operation Total[2]							417.84
PM_{10} 24-hour							
Turbine 1	0	252	1188	1440	23.30	418.97	442.27
Turbine 2	252	101	1087	1440	8.90	383.35	392.25
Turbine 3	353	101	986	1440	8.90	347.73	356.63
Startup Total							1191.15
Normal Operation Total[2]							1523.52
$PM_{2.5}$ 24-hour							
Turbine 1	0	252	1188	1440	23.30	418.97	442.27
Turbine 2	252	101	1087	1440	8.90	383.35	392.25
Turbine 3	353	101	986	1440	8.90	347.73	356.63
Startup Total							1191.15
Normal Operation Total[2]							1523.52
NO_X 24-hour[3]							
Turbine 1	0	252	1188	1440	115.10	501.34	616.44
Turbine 2	252	101	1087	1440	77.00	458.71	535.71
Turbine 3	353	101	986	1440	77.00	416.09	493.09
Startup Total							1645.24
Normal Operation Total[2]							1823.04
SO_2 24-hour[3]							
Turbine 1	0	252	1188	1440	1.28	19.40	20.68
Turbine 2	252	101	1087	1440	0.49	17.75	18.24
Turbine 3	353	101	986	1440	0.49	16.10	16.59
Startup Total							55.52
Normal Operation Total[2]							70.56

(1) Startup emissions presented are for the proposed combustion turbines.
(2) Normal operation emissions correspond to those for 100% load with duct burners.
(3) NO_X 24-hour and SO_2 24-hour calculated for determining if additional Class I visibility modeling is needed for startup.

Stack Parameters and Modeled Emission Rates

Operating Mode	Exit Velocity (fps)	Exit Temp. (°F)	CO 1-hour (lb/hr)			CO 8-hour (lb/hr)			$PM_{10}/PM_{2.5}$ 24-hour (lb/hr)		
			Turbine 1	Turbine 2	Turbine 3	Turbine 1	Turbine 2	Turbine 3	Turbine 1	Turbine 2	Turbine 3
Startup											
Cold Start(1),(2)	37.92	185.00	813.90	NA	NA	275.66	NA	NA	0.97	NA	NA
Warm Start(1),(2)	37.93	185.00	NA	NA	NA	NA	100.53	100.53	NA	0.37	0.37
Normal Operation(3)	57.83	191.20	NA	NA	NA	8.27	4.61	0.94	17.46	15.97	14.49

(1) Average exhaust velocity during startup, provided by vendor and/or Dominion.
(2) Lowest exit temperature for 60% load from performance data provided by vendor and/or Dominion.
(3) Exit velocity and temperature for the 100% load with duct burner from performance data provided by vendor and/or Dominion.

Annual Averaging Period Startup Summary

Operating Mode	hr/yr	NO_X		PM_{10}	
		lb/hr	tpy	lb/hr	tpy
Startup					
Offline	1,728	0.00	0	0.00	0
Without duct burning	811	21.70	8.8	15.51	6.3
With duct burning	6,000	25.32	76.0	21.16	63.5
Hot start	125	83.86	5.2	5.72	0.4
Warm start	25	45.74	0.6	5.29	0.1
Cold start	25	27.40	0.3	5.55	0.1
Shutdown	46	102.00	2.3	5.57	0.1
TOTALS	8,760		**93.2**		**70.4**
Normal Operation					
100% load					
Without duct burning	2,760	21.70	29.9	15.51	21.4
With duct burning	6,000	25.32	76.0	21.16	63.5
TOTALS	8,760		**105.9**		**84.9**
100% load w/o duct burners	8,760	21.70	**95.0**	15.51	**67.9**

Stack Parameters and Modeled Emission Rates for Annual Pollutants

Operating Mode	Exit Velocity (fps)	Exit Temp. (°F)	NO_X Annual (lb/hr)			$PM_{10}/PM_{2.5}$ Annual (lb/hr)		
			Turbine 1	Turbine 2	Turbine 3	Turbine 1	Turbine 2	Turbine 3
Startup[(1),(2)]	32.375	184.90	1.93	1.93	1.93	0.14	0.14	0.14
Normal Operation[(3)]								
100% with Duct Burner	57.83	191.20	19.35	19.35	19.35	15.93	15.93	15.93
100%	57.74	197.71	19.35	19.35	19.35	15.93	15.93	15.93
75%	48.32	191.50	19.35	19.35	19.35	15.93	15.93	15.93
60%	41.16	185.00	19.35	19.35	19.35	15.93	15.93	15.93

(1) Average exhaust velocity across all types of startups and shutdown, provided by the vendor and/or Dominion.
(2) Lowest exit temperature for 60% load from performance data provided by vendor and/or Dominion.
(3) Exit velocity and temperature from performance data provided by vendor and/or Dominion.

Attachment B

Class I Area Visibility Analysis Results

Number of Excursion Hours for Each Viewpoint Using FLAG Visibility Thresholds

Predicted Number of Excursion Hours Over 5 Years (at least one visibility parameter exceeding significance threshold) 3 Gas-Fired Turbines						
Wind from (degrees) -->	**0**	**10**	**20**	**30**	**Total**	**Percentage of Daytime Hours (%)**
Shenandoah Valley Overlook	5	(1)	(1)	0	5	0.02%
Dickey Ridge	94	(1)	(1)	0	94	0.43%
Signal Knob Overlook	99	(1)	(1)	16	115	0.52%
Compton Gap Road	(1)	32	16	2	50	0.23%
Lands Run Road Gate	(1)	(1)	26	0	26	0.12%
Excursion Hours(2)	114	32	27	16	189	

(1) Indicates that results for the given wind direction and viewpoint were not taken into account because the viewpoint is within 10° of the downwind axis of the source.
(2) Number of non-overlapping hours with a parameter excursion at one or more observation points.

Distribution of Excursion Hours for |C| and ΔE

Predicted Number of Excursion Hours Over 5 Years (|C| and ΔE for sky or terrain exceeding significance threshold) 3 Gas-Fired Turbines											
Observation Point -->	**Compton Gap Road**			**Dickey Ridge**		**Signal Knob Overlook**		**Lands Run**		**Shenandoah Valley Overlook**	
Wind from degrees/north -->	**10**	**20**	**30**	**0**	**30**	**0**	**30**	**20**	**30**	**0**	**30**
Hours with Contrast Excursions											
Sky Background	3	0	0	2	0	3	0	5	0	5	0
Terrain Background	32	16	2	94	0	99	16	26	0	0	0
Contrast Total	32	16	2	94	0	99	16	26	0	5	0
Hours with delta E Excursions											
Sky Background	0	0	0	7	0	9	0	5	0	4	0
Terrain Background	15	5	1	22	0	36	11	15	0	0	0
Delta E Total	15	5	1	25	0	36	11	16	0	4	0
Total Excursion Hours	**32**	**16**	**2**	**94**	**0**	**99**	**16**	**26**	**0**	**5**	**0**

Refined Number of Excursion Hours for Each Viewpoint Accounting for Realistic Visibility Parameter Thresholds

Predicted Number of Excursion Hours Over 5 Years Based on the Apparent Plume Width (at least one visibility parameter exceeding significance threshold) 3 Gas-Fired Turbines						
Wind from (degrees) -->	**0**	**10**	**20**	**30**	**Total**	**Percentage of Daytime Hours (%)**
Shenandoah Valley Overlook	3	(1)	(1)	0	3	0.01%
Dickey Ridge	16	(1)	(1)	0	16	0.07%
Signal Knob Overlook	27	(1)	(1)	2	29	0.13%
Compton Gap Road	(1)	13	4	0	17	0.08%
Lands Run Road Gate	(1)	(1)	8	0	8	0.04%
Excursion Hours[2]	33	13	8	2	56	

(1) Indicates that results for the given wind direction and viewpoint were not taken into account because the viewpoint is within 10° of the downwind axis of the source.
(2) Number of non-overlapping hours with a parameter excursion at one or more observation points.

ATTACHMENT D:

Summary of Filterable PM-10 from Russell City Energy PSD Permit

ATTACHMENT E:

Document List

PM10 (lb/hr)

Site	Unit	Date	Filterable	Condensible	Total	% filterable of Total	limit w/duct lb/hr	limit w/o duct lb/hr	
MEC	1	2005	1.576	3.973	5.549	28%	12	9	
	2		1.591	3.815	5.406	29%	12	9	
MEC	1	2007	1.489	2.241	3.73	40%	12	9	
	2		1.575	2.11	3.685	43%	12	9	
	1	2007	1.504	2.24	3.744	40%	12	9	
	2		1.413	2.359	3.772	37%	12	9	
MEC	1	2006	1.341	3.433	4.774	28%	12	9	
	2		2.011	3.567	5.578	36%	12	9	
	1	2006	1.546	2.381	3.927	39%	12	9	
	2		1.388	1.634	3.022	46%	12	9	
MEC	1	2008	1.6439	2.0827	3.7266	44%	12	9	
	2		1.6347	1.8353	3.47	47%	12	9	
MEC	1	2009	1.5935	5.5129	7.1064	22%	12	9	
	2		1.5644	8.1702	9.7343	16%	12	9	
DEC	1	2008	1.822	3.359	5.181	35%	9	9	
	2		1.745	2.464	4.209	41%	9	9	
	3		1.848	2.696	4.544	41%	9	9	
DEC	1	2002	1.04		5.4	19%	9	9	
	2		0.75		2.37	32%	9	9	
	3		0.62		2.36	26%	9	9	
DEC	1	2003	0.07	3.01	3.08	2%	9	9	
	2		2.37	2.87	5.24	45%	9	9	
	3		1.05	2.96	4.01	26%	9	9	
	1	2004	1.997	2.578	4.575	44%	9	9	
	2		2.765	2.55	5.316	52%	9	9	
	3		2.542	3.316	5.858	43%	9	9	
	1	2006	1.85	2.265	4.115	45%	9	9	
	2		1.906	2.589	4.495	42%	9	9	
	3		1.953	3.603	5.555	35%	9	9	
	1	2007	2.303	2.39	4.693	49%	9	9	
	2		2.457	2.628	5.085	48%	9	9	
	3		3.144	2.424	5.568	56%	9	9	
Pastoria	1	2005	0.72	2.32	3.04	24%	9	9	
	2	2005	2.05	1.8	3.85	53%	9	9	
	4	2005	2.44	2.54	4.98	49%	9	9	
	1	2006	5.03	1.76	6.79	74%	9	9	
	2	2006	5.27	1.11	6.38	83%	9	9	
	4	2006	4.32	1.92	6.3	69%	9	9	
	1	2007	4.81	1.87	6.68	72%	9	9	
	2	2007	5.68	1.34	7.03	81%	9	9	
	4	2007	5.05	1.22	6.27	81%	9	9	
	1	2008	6.03	1.28	7.31	82%	9	9	
	2	2008	2.25	1.13	3.38	67%	9	9	
	4	2008	5.61	2.41	8.02	70%	9	9	Longer test runs will be used on the next sampling.
Southpoint	1	2007	2.784	1.837	4.622	60%	18	22.8	
	2		0.619	2.717	3.336	19%	18	22.8	
	1	2007	1.343	4.256	5.599	24%	18	22.8	
	2		0.484	2.397	2.881	17%	18	22.8	
	1		2.322	8.331	10.65	22%	18	22.8	
	2		0.488	2.659	3.147	16%	18	22.8	

	1	2008	0.479	3.054	3.533	14%	18	22.8
	2		1.17	2.22	3.39	35%	18	22.8
	1	2008	0.5053	2.345	2.85	18%	18	22.8
	2		1.053	1.853	2.906	36%	18	22.8
	1	2006	0.928	7.462	8.391	11%	18	22.8
	1		2.784	1.837	4.622	60%	18	22.8
	2		0.619	2.717	3.336	19%	18	22.8
LMEC	1	2003	0.02		1.217	2%	9	9
	2		0.44		2.236	20%	9	9
	1	2001	1.28	3.03	4.31	30%	9	9
	2		0.86	1.95	2.81	31%	9	9
	1	2004	2.051	1.529	3.58	57%	9	9
	2	2004	2.061	1.555	3.616	57%	9	9
	1	2006	1.67	3.794	5.464	31%	9	9
	2		1.626	2.11	3.736	44%	9	9
	1	2007	1.777	1.884	3.662	49%	9	9
	2		1.658	1.93	3.589	46%	9	9
	1	2008	1.645	2.139	3.784	43%	9	9
	2		1.601	2.212	3.813	42%	9	9
Sutter	1	2001	1.11	1.78	2.87	39%	11.50	11.50
	2	2001	0.59	1.77	2.36	25%	11.50	11.50
	1	2007	0.909	2.484	3.393	27%	11.5	11.5
	2		0.806	2.873	3.679	22%	11.5	11.5
Mankato	2	2006			6.36			

Average **4.58**

Plant	Location	Turbine
DEC (Delta Energy Center)	Pittsburg, Ca	Pratt and Whitney
MEC (Metcalf Energy Center)	San Jose, CA	Siemens 501F
Pastoria	Lebec, CA	GE Frame 7
Southpoint	Mohave Co, AZ	Siemens 501F
LMEC (Los Medanos)	Pittsburg, CA	GE Frame 7
Sutter	Yuba City, CA	Siemens 501F
Mankato	Mankato, MN	Siemens 501F

ADDENDUM TO PERMIT ENGINEERING EVALUATION
Dated September 30, 2010 for
Dominion – Warren County Power Station
Registration 81391

During the public comment period for Dominion-WCPS, several reductions in emission limits were proposed by Dominion and significant changes were made to the mitigation plan included in the draft PSD permit.

Accordingly, the following attachments to the Permit Engineering Evaluation were revised and have been included with this addendum:

- Attachment A – Maximum Annual Turbine Emissions with Startups and Shutdowns
- Attachment C – DEQ Air Quality Modeling Analysis Memorandum

Attachment A

Table B-4 Maximum Annual Emissions with Startups and Shutdowns - Mitsubishi M501 GAC

Operating Parameters - Each Unit

			Potential Emission Rates (Per Turbine)				3x3x1 Configuration
Parameter	Combustion Turbine w/ Duct Firing	Combustion Turbine w/out Duct Firing	Annual Emissions based on DB Firing & CT Only Operating Hour Limits	Annual Emissions Based on CT Only Year-Round	Annual Emissions with Startup and Shutdown	Worst-Case Annual Emissions	Worst-Case Annual Emissions (Total)
Operating Hours	6000 hr/yr	2760 hr/yr					
NOx:	25.3 lb/hr	21.7 lb/hr	105.9 ton/yr	95.0 ton/yr	89.2 ton/yr	105.9 ton/yr	317.7 ton/yr
CO:	17.4 lb/hr	9.9 lb/hr	65.9 ton/yr	43.4 ton/yr	116.2 ton/yr	116.2 ton/yr	348.5 ton/yr
VOC:	6.1 lb/hr	2.6 lb/hr	22.1 ton/yr	11.6 ton/yr	60.3 ton/yr	60.3 ton/yr	181.0 ton/yr
PM10/PM2.5:	14.00 lb/hr	8.00 lb/hr	53.0 ton/yr	35.0 ton/yr	45.7 ton/yr	53.0 ton/yr	159.1 ton/yr
SO2:	0.98 lb/hr	0.84 lb/hr	4.1 ton/yr	3.7 ton/yr	3.3 ton/yr	4.1 ton/yr	12.3 ton/yr
H2SO4:	0.88 lb/hr	0.40 lb/hr	3.2 ton/yr	1.7 ton/yr	<3.2 ton/yr	3.2 ton/yr	9.5 ton/yr
NH3:	23.4 lb/hr	20.0 lb/hr	97.8 ton/yr	87.8 ton/yr	<97.8 ton/yr	97.8 ton/yr	293.5 ton/yr
Lead:	0.0017 lb/hr	0.0015 lb/hr	0.007 ton/yr	0.006 ton/yr	<0.007 ton/yr	0.007 ton/yr	0.022 ton/yr

Notes:

Duct burner capacity estimated at 500 MMBtu/hr (at 100% load).

Hourly emission estimates are based on *worst-case ambient conditions* (*i.e., temperature, % relative humidity*) at normal operations.

For lead, emission rates for natural gas firing are based on the worst-case firing rate, a heat content value of 1020 Btu/scf and the AP-42 emission factor of 0.0005 lb/MMcf.

For "Annual emissions with DB Firing at Operating Hour Limit", emission estimates were calculated as follows:

Annual Emissions (ton/yr) = [Pollutant Emission Rate, CT w/DB (lb/hr) x Operating Hours, CT w/DB (hr/yr) + Pollutant Emission Rate, CT only (lb/hr) x Operating Hours, CT only (hr/yr)] / (2000 lb / ton)

For "annual emissions with no DB firing", emission estimates for the natural gas firing (CT only) were based on 8760 operating hours per year.

ATTACHMENT C

MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY
Office of Air Data Analysis and Planning

629 East Main Street, Richmond, VA 23219
8th Floor

804/698-4000

To: Janardan Pandey, Air Permit Manager (VRO)

From: Mike Kiss, Coordinator - Air Quality Assessments Group (AQAG)

Date: October 4, 2010 (Revised December 6, 2010)

Subject: Virginia Department of Environmental Quality (DEQ) Technical Review of the Air Quality Analyses in Support of the PSD Permit Application for the Proposed Dominion Natural Gas-Fired Power Plant in Warren County, Virginia (Warren County Power Station)

Copies: Tamera Thompson, Bobby Lute

I. Project Background

Virginia Electric and Power Company, a subsidiary of Dominion Resources, Inc. (Dominion), has proposed to construct and operate a 1280 megawatt (MW) natural gas-fired combined-cycle electric generating facility in the Warren Industrial Park, approximately one mile north of Interstate Route 66, in Warren County, Virginia. The proposed new facility, called the Warren County Power Station, will consist of three identical natural gas-fired only turbines, each with its own duct-fired heat recovery steam generator (HRSG), one reheat condensing steam turbine generator, three inlet turbine chillers, a natural gas-fired only auxiliary boiler, a diesel-fired emergency generator and fire water pump engine, and a natural gas-fired only fuel heater. Dominion has proposed to install Mitsubishi (M501 GAC) turbines.

The proposed facility meets the definition of major source under 9 VAC 5 Chapter 80, Article 8 (Prevention of Significant Deterioration (PSD)) of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution because it is a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr heat input capacity and has the potential to emit 100 tons per year or more of a regulated pollutant. The pollutants subject to PSD review are nitrogen oxides (NO_X), particulate matter having an aerodynamic diameter equal to or less than 10 microns (PM_{10}), particulate matter having an aerodynamic diameter equal to or less than 2.5 microns ($PM_{2.5}$), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid mist. As a result, PSD regulations require an air quality analysis be performed that demonstrates that the projected air emissions from the proposed facility will neither cause or significantly contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. In addition, PSD regulations require that an additional impact analysis consisting of a soil and vegetation analysis, a growth analysis and a visibility impairment analysis be conducted. An analysis of the project's impact on air quality and air quality related values (AQRVs) in any affected Class I area is also required. The AQRV analysis is subject to review by the AQAG and the appropriate Federal Land Manager (FLM).

The following is a summary of the AQAG's review of the required air quality analyses for the Warren County Power Station for both Class I and Class II PSD areas. The worst-case impacts from all operating loads, including startup and shutdown operations, are presented in this memorandum.

The Class I and Class II air quality analyses received by the AQAG were dated July 2 and 14, 2010. Supplemental analyses received by the AQAG were dated August 27, 2010 and September 2, 2010.

II. Modeling Methodology

The Class I and Class II air quality modeling analyses conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and were performed in accordance with their respective approved modeling methodology that were included in a protocol that was submitted in advance by the proposed facility. DEQ approved the protocol on March 23, 2010. The FLMs were provided an opportunity to comment on the Class I area modeling methodology. The United States Forest Service (USFS) provided comments in an e-mail dated February 4. 2010. The USFS concluded, based on the emission rates in the protocol and distances to the Class I areas, that *"modeling would not show any significant additional impacts to air quality related values (AQRV) at the Class I areas administered by the US Forest Service."* Therefore, the USFS did not request that a Class I AQRV analysis be included in the PSD permit application. The National Park Service (NPS) FLM provided comments and approved the modeling protocol in an e-mail dated April 1, 2010. The NPS issues were also discussed and agreed upon during a conference call on April 19, 2010.

The air quality model used for both Class I and Class II area analyses was the most recent version of the AERMOD modeling system (Version 09292). The AERMOD modeling system is the preferred EPA-approved regulatory model for near-field applications and is contained in Appendix W of 40 CFR Part 51. The PLUVUE II model (Version 96170) was also used to assess plume impairment in Shenandoah National Park. This model is approved by the FLMs for evaluating plume impairment (i.e., near-field visibility impacts) in Class I areas.

III. Modeling Results

A. Class II Area - *Preliminary Modeling Analysis*

A preliminary modeling analysis for criteria pollutants was conducted in accordance with PSD regulations to predict the maximum ambient air impacts. The preliminary analysis modeled emissions from the proposed facility only to determine whether or not the impacts were above the applicable significant impact levels (SILs). For those pollutants for which maximum predicted impacts were less than the SIL, no further analyses was required (i.e., predicted maximum impacts less than SILs are considered insignificant and of no further concern). For impacts predicted to be equal to or greater than the SIL, a more refined air quality modeling analysis (i.e., full impact or cumulative impact analysis) is required to assess compliance with the NAAQS and PSD increment.

The emissions associated with four (4) representative operating loads were modeled, as well as startup/shutdown emissions. Attachment A contains the specific emission rates and corresponding stack parameters that were modeled. Table 1 below shows the maximum predicted ambient air concentrations.

Table 1
Class II Preliminary Modeling Analysis Results vs. Significant Impact Levels

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility ($\mu g/m^3$)	Class II Significant Impact Level ($\mu g/m^3$)
NO_2	1-Hour	N/A[1]	7.5
	Annual	0.60	1
PM_{10}	24-hour	6.74	5
	Annual	0.43	1
$PM_{2.5}$	24-hour	6.74	1.2
	Annual	0.41	0.3
CO	1-hour	869.70	2,000
	8-hour	139.21	500

(1) SIL modeling not conducted for 1-hour NO_2. Worst-case assumption was used (i.e., project emissions are significant out to the valid range of the model (i.e., 50 km)).

The modeling results for NO_2 (annual averaging period), PM_{10} (annual averaging period), and CO (1-hour and 8-hour averaging periods) were less than the applicable SILs. Therefore, a full impact analysis for these pollutants and averaging periods was not required. However, a full impact analysis for NO_2 (1-hour averaging period), PM_{10} (24-hour averaging period), and $PM_{2.5}$ (24-hour and annual averaging periods) was conducted because the preliminary modeling analysis results exceeded the applicable SILs.

The AQAG has adopted the NO_2 (1-hour) SIL in Table 1 based on a review of the following documentation:

> *Guidance Concerning the Implementation of the 1-hour NO2 NAAQS for the Prevention of Significant Deterioration Program, Stephen D. Page, EPA, June 29, 2010.*

The staff concurs with the EPA recommendations in this memorandum that it is appropriate to derive an interim 1-hour NO_2 SIL by using an impact equal to 4% of the 1-hour NO_2 NAAQS (4 ppb is equivalent to 7.5 $\mu g/m^3$). The AQAG believes that it is reasonable to adopt this value based on consideration of the impact level relative to the NAAQS and past EPA rationale for existing short-term averaging period SILs. The use of 4% of the NAAQS as a threshold is also consistent with previous EPA rulemaking and supporting documentation as described in the June 29, 2010 EPA memorandum.

The AQAG has adopted the $PM_{2.5}$ (24-hour and annual) SILs in Table 1 based on a review of the following documentation:

> *Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5)-Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Proposed Rule, 40 CFR Parts 51 and 52, September 21, 2007.*

The AQAG determined that EPA's Option 3 on Page 54115 of the Federal Register was appropriate as an interim value based on (1) the fact that these values are the most stringent option proposed by EPA, (2) it uses the existing PM_{10} SIL to PM_{10} NAAQS ratio as a basis for its derivation, and (3) staff has verbal confirmation from EPA that the final SIL will be selected from one of the proposed options. It should be noted that air quality impacts resulting from direct (primary) PM_{10} and $PM_{2.5}$ emissions can often be correlated. In fact, direct PM_{10} and $PM_{2.5}$ emissions from a natural gas-fired combined-cycle electric generating facility are usually identical for all practical purposes.

B. Class II Area – Cumulative Impact Modeling Analysis

The cumulative impact analysis described below consisted of separate analyses to assess compliance with the NAAQS for NO_2, PM_{10}, and $PM_{2.5}$ and the PSD increment for PM_{10} for the indicated averaging periods. No PSD increment analyses were required for NO_2 (1-hour averaging period) and $PM_{2.5}$ (24-hour and annual averaging periods) because EPA has not yet promulgated Class II PSD increments for these pollutants and averaging periods.

It is important to note that the cumulative impact modeling results (both NAAQS and PSD increment) can sometimes be less than the "source only" modeling results in Table 1 of this memorandum. This is due to the fact that source only modeling uses the maximum concentration to determine significance; whereas the cumulative modeling results reflect the form of the air quality standard. For example, the following criteria must be met to attain the NAAQS:

- CO (1-hour and 8-hour) - Not to be exceeded more than once per year
- NO_2 (1-hour) - To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed the standard
- NO_2 (annual) - Never to exceed the standard
- PM_{10} (24-hour) - Not to be exceeded more than once per year on average over 3 years
- $PM_{2.5}$ (24-hour) - To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed the standard
- $PM_{2.5}$ (annual) - To attain this standard, the 3-year average of the weighted annual mean $PM_{2.5}$ concentrations from single or multiple community-oriented monitors must not exceed the standard

NAAQS Analysis

The NAAQS analysis included emissions from the proposed source, emissions from existing sources from Virginia, West Virginia, and Maryland and representative ambient background concentrations of NO_2, PM_{10}, and $PM_{2.5}$. The results of the analysis are presented in Table 2 and demonstrate compliance with the applicable NAAQS.

Table 2
NAAQS Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	109.07	7.97[1]	75.2	184.27	188
PM_{10}	24-hour	4.98	4.92	34.7	39.68	150
$PM_{2.5}$	24-hour	4.38	4.23	28.0	32.38	35
	Annual	0.48	0.38	11.7	12.18	15

[1] The project contribution provided represents the highest single year's concentration that significantly contributes to the Total Concentration.

PSD Increment Analysis

The 24-hour PM_{10} PSD increment analysis included emissions from the proposed source and emissions from increment-consuming sources from Virginia, West Virginia, and Maryland. Table 3 below presents the results of the analysis and shows that the 24-hour PM_{10} concentration was below the PSD increment.

Table 3
PSD Increment Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
PM_{10}	24-hour	4.98	4.92	30

See Section D of this memorandum (Other Modeling Considerations) for a discussion on the recently promulgated $PM_{2.5}$ increments.

NAAQS and PSD Increment Analyses Conclusions

Based on DEQ's review of the NAAQS and PSD increment analyses, the proposed Warren County Power Station does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment.

Toxics Analysis

The source is subject to the state toxics regulations at 9 VAC 5-60-300 et al. An analysis was conducted in accordance with the regulations and the predicted concentrations for each toxic pollutant were below their respective Significant Ambient Air Concentrations (SAAC). Table 4 summarizes the toxic pollutant modeling analysis results.

Table 4
Toxics Analysis Maximum Predicted Concentrations

Toxic Pollutant	Averaging Period	Maximum Modeled Concentration From Project ($\mu g/m^3$)	SAAC ($\mu g/m^3$)
Acrolein	1-hour	4.36E-02	17.25
	Annual	2.30E-04	0.46
Formaldehyde	1-hour	1.58E+00	62.5
	Annual	9.24E-03	2.4

Toxic Pollutant	Averaging Period	Maximum Modeled Concentration From Project ($\mu g/m^3$)	SAAC ($\mu g/m^3$)
Cadmium	1-hour	1.23E-02	2.5
Chromium	1-hour	1.56E-02	2.5
Nickel	1-hour	2.34E-02	5

Additional Impact Analysis

In accordance with the PSD regulations, additional impact analyses were performed to assess the impacts from the proposed facility on visibility, vegetation and soils, and the potential for and impact of secondary growth. These analyses are discussed below.

Visibility

A screening modeling analysis was conducted to assess the potential for visual plume impacts in Class II areas within 50 kilometers (km) of the project site. A review of National Parks in Virginia indicated that the Appalachian Trail is the closest identified potentially sensitive area outside Shenandoah National Park. The project site is about 11 km northwest of the nearest approach of the Appalachian Trail.

The visibility screening modeling approach followed guidance provided in EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised) (October 1992; EPA-454/R-92-023)*. The two visibility metrics that were evaluated in the VISCREEN modeling analysis are:

- **Plume contrast (|C|)**: Contrast can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object (e.g., plume) and its background (e.g., sky). Plume contrast results from an increase or decrease in light transmitted from the viewing background through the plume to the observer.

- **Plume perceptibility (ΔE)**: A parameter used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background such as the sky, a cloud, or a terrain feature.

The VISCREEN results were developed for startup/shutdown and normal operating scenarios. All results were below the significance criteria in the nearest Class II National Park. Therefore, the plume is expected to be imperceptible against the background sky and the terrain. A Class I area visibility analysis was performed for Shenandoah National Park and is discussed in Section C of this memorandum (Class I Area Modeling Analysis).

The visibility in the area near the proposed facility will be protected by operational requirements, such as air pollution controls and clean burning fuels, and stringent limits on visible emissions that are incorporated into the draft permit.

Vegetation and Soils

An analysis on sensitive vegetation types with significant commercial or recreational value was conducted. The analysis compared maximum predicted concentrations from the proposed facility against a range of injury thresholds found in various peer-reviewed research articles as well as criteria contained in the EPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA, 1981)*. Table 5 shows the maximum predicted concentrations for NO_2, PM_{10}, and CO were all below the respective thresholds (i.e., the minimum reported levels at which damage or growth effects to vegetation may occur). As a result, no adverse impacts on vegetation are expected.

Table 5
Comparison of Vegetation Sensitivity Thresholds to Maximum Modeled Concentrations from the Warren County Power Station

Pollutant	Averaging Period	Maximum Modeled Concentration From Proposed Facility ($\mu g/m^3$)	Sensitive Vegetation Threshold ($\mu g/m^3$)
NO_2	1-hour	342.97[(1)]	940
	4-hour	73.56	3,760
	1-month	1.12	564
	Annual	0.60	94
PM_{10}	24-hour	6.74	150
	Annual	0.43	50
CO	1-week	7.65	1,800,000

(1) Please note the 1-hour NO_2 concentration is the highest modeled concentration over the 5 modeled years. This is not consistent with how the new 1-hour NO_2 NAAQS is defined.

The impact of the emissions on soils in the vicinity of the proposed project was evaluated. The soil type was determined from data collected from the United States Department of Agriculture's Natural Resources Conservation Service (NRCS) Soil Survey Geographic (SSGUGO) database and the NRCS Web Soil Survey tool. The soil types within the nearby counties of Warren, Clarke, Frederick, and Shenandoah are similar in composition.

The predominant soil types in Warren County are silt and stony loams. In Clarke County, the predominate soil types are silt and sandy loams with rocky outcrops. Frederick County contains a mixture of silt and gravely/cobbly loams with some areas of fine sandy loams. In Shenandoah County, the soil types are also a mixture of silt, clay, and cobbly and sandy loams.

The soil types in the adjacent counties are generally considered to have a moderate to high buffering capacity and have a higher capacity to absorb acidic deposition without changing the soil pH. Based on the soil types and quantity of emissions from the proposed project, no adverse impact on local soils is anticipated.

A discussion of the impacts of acidic deposition in Shenandoah National Park is provided in Section C of this memorandum (Class I Area Modeling Analysis).

Growth

The work force for the proposed facility is expected to range from 400 to 600 jobs during various phases of the construction. It is expected that a significant regional construction force is already available to build the proposed facility. Therefore, it is anticipated that no new housing, commercial or industrial construction is necessary to support the Warren County Power Station during the two-year construction schedule. The proposed facility will also require approximately 20 to 25 permanent positions. It is assumed that individuals that already live in the region will perform a number of these jobs. No new housing requirements are expected for any new personnel moving to the area. In addition, due to the small number of new individuals expected to move into the area to support the Warren County Power Station and the existence of some commercial activity in the area, new commercial construction would not be necessary to support the permanent work force. Additionally, no significant level of industrial related support will be necessary for the Warren County Power Station. Therefore, industrial growth is not expected.

Based on the growth expectations discussed above, no new significant emissions from secondary growth during the construction and operation phases of the Warren County Power Station are anticipated.

C. Class I Area Modeling Analysis

The FLMs are provided reviewing authority of Class I areas that may be affected by emissions from a proposed source by the PSD regulations and are specifically charged with protecting the Air Quality Related Values (AQRV) within the Class I areas. The closest Class I area to the proposed facility is the Shenandoah National Park (SNP). Its nearest point is approximately 7.1 km from the project site. The next closest Class I area, Dolly Sods Wilderness Area in West Virginia, is approximately 100 km upwind (based on the prevailing wind direction) from the proposed facility.

Modeling guidance provided in 2008 by the Federal Land Managers' Air Quality Related Values Work Group (FLAG), provides screening criteria for determining whether a source may be excluded from performing a Class I area AQRV modeling analysis. The FLMs may consider excluding a source from modeling if its total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions) divided by the distance (in km) from the Class I area is less than or equal to 10. The sum of the emissions for the proposed project is not expected to exceed approximately 600 tons per year (tpy). Therefore, the FLAG 2008 screening distance for the SNP is 84.5 (600 tpy/7.1 km). The screening distance for all other Class I areas is less than 6 (600 tpy/100 km or greater). Based on the FLM screening criteria, an AQRV analysis was conducted for the SNP. The USFS did not require an analysis of the more distant Class I areas (Dolly Sods Wilderness Area, Otter Creek Wilderness Area, and James River Face Wilderness Area).

A preliminary modeling analysis for NO_2, PM_{10}, and $PM_{2.5}$ was conducted to determine whether or not the predicted maximum ambient air impacts in the SNP were above the Class I SILs. CO emissions were not modeled because the maximum ambient air impacts for the Class II area were well below the applicable Class II SILs (see Table 1 for details) and there is no Class I area SIL for this pollutant. The emissions used in the Class I area modeling were the same as those used for the Class II area modeling. A more refined air quality modeling analysis (i.e., cumulative impact analysis) was required to assess compliance with the NAAQS and Class I PSD increments for impacts predicted to be equal to or above the Class I SIL. No additional air quality analysis was required for pollutants when the proposed project's impacts were less than the SIL.

The proposed facility's maximum predicted ambient air concentrations for NO_2, PM_{10}, and $PM_{2.5}$ in the SNP are presented in Table 6. The predicted concentrations for all pollutants were above all of the applicable Class I SILs in the SNP. Therefore, a cumulative impact analysis was required for these pollutants. It is important to note that no analysis was required for demonstrating compliance with the annual PM_{10} NAAQS because the standard was revoked by EPA in 2006. Additionally, no Class I PSD increment analysis for $PM_{2.5}$ and 1-hour NO_2 was required because EPA has not yet promulgated these Class I PSD increments. See Section D of this memorandum (Other Modeling Considerations) for a discussion on the recently promulgated $PM_{2.5}$ increments.

Table 6
Summary of Maximum Predicted Concentrations from the Proposed Facility for Shenandoah National Park

Pollutant	Averaging Period	Maximum Predicted Concentration From Proposed Facility ($\mu g/m^3$)	Class I Significant Impact Level ($\mu g/m^3$)
NO_2	1-hour	N/A[1]	7.5
	Annual	0.27	0.1
PM_{10}	24-hour	5.55	0.3
	Annual	0.21	0.2
$PM_{2.5}$	24-hour	5.55	0.07
	Annual	0.21	0.06

[1] SIL modeling not conducted for 1-hour NO_2. Worst-case assumption was used (i.e., project emissions are significant out to the valid range of the model (i.e., 50 km)).

NAAQS Analysis

The NAAQS analysis for SNP included emissions from the proposed source, emissions from existing sources from Virginia and West Virginia, and representative ambient background concentrations of NO_2, PM_{10}, and $PM_{2.5}$. The results of the analysis are presented in Table 7 and demonstrate compliance with the NO_2, PM_{10}, and $PM_{2.5}$ NAAQS. Please note that the 1-hour NO_2 receptor grid did not differentiate between Class I and Class II receptors. Therefore, the NO_2 concentration presented in the table below is the highest design value for both Class I and Class II areas (i.e., the same value as presented in Table 2).

Table 7
NAAQS Modeling - Cumulative Impact Results for Shenandoah National Park

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	109.07	7.97[1]	75.2	184.27	188
	Annual	0.45	0.27	12.5	12.95	100
PM_{10}	24-hour	5.15	5.10	34.7	39.85	150
$PM_{2.5}$	24-hour	3.74	3.72	28.0	31.74	35
	Annual	0.13	0.11	11.7	11.83	15

[1] The project contribution provided represents the highest single year's concentration that significantly contributes to the Total Concentration.

PSD Increment Analysis

The PSD increment analysis included emissions from the proposed source and emissions from increment-consuming sources from Virginia and West Virginia. Table 8 presents the results of the PSD increment analysis. All predicted impacts are less than the applicable PSD increments.

Table 8
PSD Increment Modeling - Cumulative Impact Results for Shenandoah National Park

Pollutant	Averaging Period	Modeled Concentration From All Sources ($\mu g/m^3$)	Project Contribution to Modeled Concentration ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
NO_2	Annual	0.45	0.27	2.5
PM_{10}	24-hour	5.15	5.10	8
	Annual	0.27	0.21	4

See Section D of this memorandum (Other Modeling Considerations) for a discussion on the recently promulgated $PM_{2.5}$ increments.

Air Quality Related Values

An AQRV analysis (acidic deposition and visibility) was performed for the Class I area (i.e., SNP) and is discussed in the sections below.

Acidic Deposition

An analysis of the potential sulfur (S) and nitrogen (N) deposition at the SNP was conducted in accordance with guidance from the FLM. The FLM approved the protocol on April 19, 2010. The results of the analysis were compared to the sulfur and nitrogen deposition analysis threshold (DAT) of 0.010 kilograms per hectare per year (kg/ha/yr) for eastern Class I areas. The DAT is defined as the additional amount of sulfur or nitrogen deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The DAT is a deposition threshold, not necessarily an adverse impact threshold. If the additional amount of deposition is greater than or equal to the DAT, further analysis is usually required by DEQ and the FLM.

Table 9 presents a summary of the maximum predicted sulfur and nitrogen deposition rates for the SNP. The maximum predicted sulfur deposition rate was below the DAT and the maximum predicted nitrogen deposition rate was above the DAT. Two models were run to obtain these results. AERMOD was run in accordance with the approved modeling protocol. CALPUFF was run by the DEQ, FLM, and the applicant to provide supplemental information on nitrogen deposition.

Table 9
Maximum Predicted Annual Sulfur and Nitrogen Deposition Rates from the Proposed Facility for Shenandoah National Park

AERMOD Sulfur Deposition (kg N/ha/yr)	Deposition Analysis Threshold for S (kg N/ha/yr)	AERMOD Nitrogen Deposition (kg S/ha/yr)	CALPUFF Nitrogen Deposition (kg S/ha/yr)	Deposition Analysis Threshold for N (kg S/ha/yr)
0.008	0.010	0.04	0.022	0.010

Both the NPS and DEQ have stated concerns about acidic deposition in the SNP. DEQ continues to evaluate and respond to these issues as part of its agency obligations under the U.S. Clean Water Act. For example, DEQ issues its 305(b)/303(d) Water Quality Assessment Integrated Report (Integrated Report) every 2 years. This report provides a summary of the water quality conditions in Virginia, including SNP. DEQ develops and submits this report to the EPA every even-numbered year. The report satisfies the requirements of the U.S. Clean Water Act sections 305(b) and 303(d) and the Virginia Water Quality Monitoring, Information and Restoration Act. The goals of Virginia's water quality assessment program are to determine whether waters meet water quality standards and to establish a schedule to restore waters with impaired water quality. Additional information can be found at the following link:

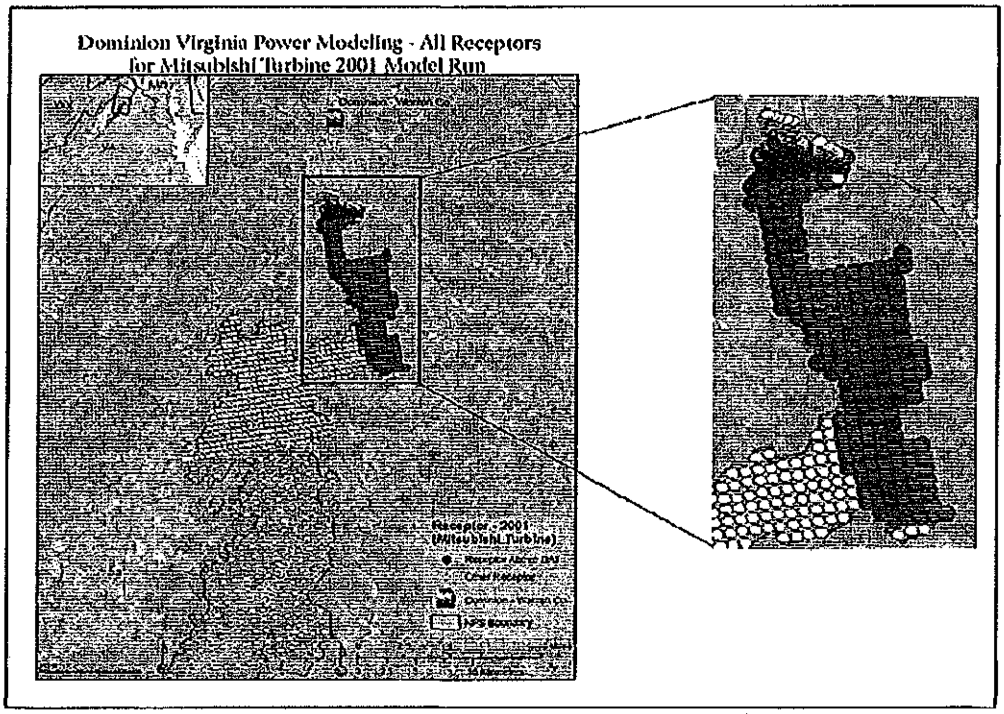
http://www.deq.virginia.gov/wqa/

Recently collected stream samples, although not certified by DEQ, indicate that stream acidification in the SNP continues to impact water quality. For example, the Shenandoah Watershed Study (SWAS) program conducts watershed research and monitoring in the Shenandoah National Park as well as other areas. The SWAS program studies acidic deposition in sensitive streams, most of which support reproducing populations of the native brook trout. The SWAS program concluded that stream water acidification is a continuing problem in Virginia's forested mountain watersheds. A link to the SWAS program is provided below:

http://swas.evsc.virginia.edu/

As previously stated, DEQ recognizes the importance of protecting the SNP from the impacts of acidic deposition. The proposed Dominion facility is subject to Acid Rain permitting requirements established under Title IV of the 1990 Clean Air Act Amendments - The Acid Rain Program. The overall goal of the Acid Rain Program is to achieve significant environmental and public health benefits through reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X), the primary causes of acid rain. The proposed facility is fueled by natural gas, the least polluting of the possible fuel sources. As a result, the Acid Rain requirements associated with this power plant will be minimal. The Acid Rain Program requirements being implemented regionally will likely result in significant long-term environmental improvements in agricultural lands, lakes, streams, and forests in Virginia and the SNP.

The NPS has expressed concern that locations within the northern end of the SNP had predicted nitrogen deposition greater than 0.020 kg/ha/yr, a value more than twice the DAT. The following figure illustrates the receptors with modeled impacts greater than the DAT. The maximum modeled nitrogen deposition at any receptor was 0.022 kg/ha/yr.



DEQ agrees additional nitrogen deposition resulting from emissions from the proposed project may adversely impact streams and aquatic biota already impaired because of acidification. The NPS comments do not specifically quantify what impact a loading of 0.022 kg/h/yr (maximum receptor) would have on a stream's pH. DEQ also supports a modeling approach which averages impacts across an individual watershed as opposed to the standard NPS practice of using the maximum impact at any one receptor to determine significance.

The NPS correctly states that DEQ has classified Jeremy's Run as a watershed in the northern portion of the SNP that is impaired for pH. It is important to note, however, that the proposed facility's impact within Jeremy's Run is below the DAT; therefore, it is not expected to significantly contribute to acidic deposition in this particular watershed using the NPS criteria.

Lastly, the pH special standard that currently applies to Jeremy's Run and other streams in the SNP is 6.5-9.5. This standard range is based on the assumption of limestone substrate in the western portion of Virginia, namely in the lower elevations of the Shenandoah Valley. Many of the streams in the SNP, such as Jeremy's Run, are defined as headwaters where the substrate is not limestone. Therefore, streams located at the higher elevations (i.e., both the western and eastern slopes of the SNP) do not fit this description. In fact, the USFS had a number of their streams with a similar substrate to those in the SNP reclassified in the last triennial review of water quality standards. These USFS streams are now subject to the statewide pH standard of 6-9.

Visibility

Plume visibility impacts inside the SNP within 50 km were evaluated using the PLUVUE II model. This approach is preferred by the FLMs and is consistent with past modeling exercises (i.e., previous permitting of the Competitive Power Ventures (CPV) project at the same site).

Several viewpoints within the Class I area were selected by the NPS for the plume visibility analysis. These are as follows:

- **Shenandoah Valley Overlook**: located about 9 km from the proposed project site, it offers views to the north toward Front Royal.

- **Dickey Ridge**: located about 11 km from the proposed project site, it offers views to the northeast within the Park and views to the southeast and southwest toward terrain within the Park.

- **Signal Knob Overlook**: located about 12.5 km from the proposed project site, it offers fairly long views to the south, southwest, and southeast within Park boundaries. In addition, there is a view toward the west to areas beyond Park boundaries.

- **Compton Gap Road**: selected as a supplemental viewpoint by the NPS due to its location at the highest point along Compton Gap Road, about 14.6 km from the project site. It offers long views of Park terrain toward the southwest and shorter views toward the west and northwest.

- **Lands Run Road Gate**: selected as a supplemental viewpoint by the NPS for its location where Lands Run Road crosses the western boundary of the Park. It is approximately 16.5 km from the proposed project site and it offers long views to the south and southwest, although viewing distances to the east are limited by elevated terrain.

As with the Class II visibility modeling, the two metrics that were evaluated in the PLUVUE II modeling were plume contrast (|C|) and plume perceptibility (ΔE). There were two approaches used to calculate plume impairment:

- **FLAG Approach:** PLUVUE II was run for each hour identified from the 5-year meteorological period for meteorological conditions associated with the Class I Levels of Concern (an absolute value of at least 0.02 for |C| and 1.0 for ΔE). The results of the PLUVUE II analyses were summarized for each viewpoint and the probability of potential future occurrences during peak project emission periods were calculated by reviewing the frequency of hours determined to be above perceptible visibility thresholds, especially during periods of peak park visitation.

- **Refined Approach:** A refined plume impairment analysis was conducted to account for effects on plume perceptibility due to the apparent plume width. As noted by Richards et al. (2007),

  "In the real world, plumes are viewed against a background of sky or terrain that does not have a uniform luminance and color, even when there are no clouds. For faint plumes, the effect of a plume is to introduce a small distortion in the luminance and color profile of the background. As the angle subtended by a plume increases (i.e., the plume fills a larger portion of the observers total field of view), the plume is spread over a larger change in the luminance and color of the background sky. For a given value of the plume contrast or color difference, the changes in luminance and color attributable to the plume become a smaller fraction of the naturally occurring variations in the luminance and color of the background sky. Thus, it is reasonable to believe that the adjustment needed to convert laboratory contrast thresholds into thresholds appropriate for the real world increases as the plume subtended angle increases."

The procedures for implementing an adjustment to |C| and ΔE are described by Richards et al. (2007) as well as Zell et al. (2007). This involves computation of the plume angle subtended for each line of sight and simulated PLUVUE hour, computing appropriate threshold values for |C| and ΔE, and then comparing the modeled plume parameter to this threshold.

A summary of the PLUVUE II modeling results at each observer location as provided by NPS, along with the number of hours where each of the visibility criteria is exceeded, is presented in Table 10.

Table 10
Summary of the PLUVUE II Modeling Results

View Point	Total During 5-Year Period			Annual Average		
	Days	|C| Hours	ΔE Hours	Days	|C| Hours	ΔE Hours
Signal Knob Overlook	26	29	5	5	6	1
Dickey Ridge	14	16	3	3	3	1
Compton Gap Road	14	15	0	3	3	0
Lands Run Road Gate	8	8	5	2	2	1
Shenandoah Valley Overlook	3	3	0	1	1	0
Totals	65	71	13	14	15	3

The NPS evaluates the coherent plume impacts based on three criteria, namely (1) frequency, (2) duration, and (3) magnitude. The NPS concludes that the coherent plume impacts occur infrequently. They also state that, with the exception of a few 2-hour events, the duration of the impacts is not more than one hour. The NPS' concern with respect to the coherent plume impacts is based on the magnitude of the impacts. The NPS and DEQ agree that the values calculated for a few of the hours are large. For example, six of the hourly impacts over the 5-year period at the Signal Knob Overlook, as predicted by PLUVUE II, are an order of magnitude over the applicable thresholds. The largest |C| impact is 40 times the threshold and the largest ΔE impact is four times the threshold. DEQ also concurs with the NPS that some of these predicted impacts occur during September and October during the peak visitation period in the SNP.

It is important to note that the PLUVUE II modeling results are based on conservative assumptions. The model uses a monochromatic background (e.g., white, grey, black or sky (blue)) and the SNP background consists of a multi-colored background. This would result in the plume being less visible than predicted by the model. Additionally, the modeling results indicate that the plume is much less visible against the sky background than the terrain background. The applicant speculates that due to the elevated nature of the proposed facility's combined-cycle stack plumes, it is more likely to be viewed against the sky background.

The NPS concluded the visibility impacts adversely affect visibility along Skyline Drive as a result of the magnitude of the impacts. The NPS also acknowledges that these impacts would be infrequent. The conclusion that the coherent plume from the proposed plant adversely affects visibility based on the magnitude of the impacts is a value judgment made by the NPS. DEQ agrees that the visible plume impacts cannot be directly mitigated by emission reductions from other sources in other locations.

In order to address the NPS concerns, all parties (NPS, DEQ and Dominion) have reached a mutually acceptable emissions reduction plan that will result in a net environmental benefit in the SNP. As previously noted, plume impacts cannot be directly offset with emissions reductions in other locations. However, visibility impact concerns have been alleviated because all parties agree that sufficient emission reductions are included in the permit that result in a net environmental benefit to the SNP.

The detailed visibility impairment results are provided in Attachment B. The results are summarized for each viewpoint and the probability of potential future occurrences during peak project emission periods are calculated by reviewing the frequency of hours determined to be above perceptible visibility thresholds.

Summary of Class I Area Analysis

Based on DEQ's review of the modeling analyses, the proposed Warren County Power Station does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class I area PSD increment.

The PSD regulations provide reviewing authority to the FLM. The 60-day FLM review period began on September 7, 2010. In accordance with 9 VAC 5-80-1765 D, the FLM has an opportunity to notify DEQ of any adverse impact on the AQRVs. The FLM's authority to make a determination of an adverse impact on the AQRVs is invoked most frequently in the context of the preconstruction permit review procedure specified in Section 165 of the Clean Air Act.

The NPS, in its comments to DEQ, concludes that the impact of the project's emissions constitutes an adverse impact upon visibility in the SNP. The NPS is also concerned about the contribution of additional acidifying pollutants into the aquatic ecosystems and state that the project, as proposed, would have an adverse impact on the aquatic systems in the SNP.

The NPS acknowledges that all parties (NPS, DEQ and Dominion) have reached a mutually acceptable emissions reduction plan that will result in a net environmental benefit in the SNP. The NPS concludes that although plume impacts cannot be directly offset with emissions reductions in other locations, visibility impact concerns are alleviated when sufficient emission reductions are achieved to demonstrate a net environmental benefit to the SNP.

The three major elements of the mitigation plan, as identified in the NPS comments, are as follows:

1. Dominion shall permanently cease all permitted SO_2 and NO_X emissions at North Branch Power Station in Grant County, West Virginia. Based on the actual emissions in 2007-2008 and the distance and direction of North Branch Power Station from the Park, these reductions shall result in an Emission Offset of 243 tons per year (TPY) that is applied to the total annual NO_X limit. Specifically, these

emissions are being offset at a ratio of 10:1 based on the modeling conducted by the NPS. Neither the permitted nor actual SO_2 and NO_X emission reductions from the North Branch Power Station may be used as Emissions Offsets for any other purpose.

2. Dominion shall retire permanently the 175 TPY of NO_X offsets procured from World Kitchen in Martinsburg, West Virginia, as approved by the DEQ by letter of 11/17/07. Based on the distance and direction of World Kitchen from the Park, this retirement of emission reduction credits shall result in 17.5 TPY emission offsets toward the total annual NO_X limit. Specifically, these emissions are being offset at a ratio of 10:1 based on the modeling conducted by the NPS.

3. Dominion shall secure and retire Eligible SO_2 Allowances, Eligible NO_X Allowances, or Emission Reduction Credits in the amount equivalent to 70.2 TPY of Emission Offsets toward the total annual NO_X limit.

D. Other Modeling Considerations

Facilities Locating within 10 Kilometers (km) of a Class I Area

PSD regulations require that modeling should be performed for any emissions rate at a new PSD major stationary source or net emissions increase associated with a modification at an existing PSD major stationary source located within 10 kilometers (km) of a federal Class I area to determine if the maximum 24-hour average impact of the regulated pollutant in the Class I area is equal to or greater than 1.0 micrograms per cubic meter ($\mu g/m^3$) on a 24-hour basis. If the 24-hour impact is equal to or greater than 1.0 $\mu g/m^3$, the emissions rate associated with the new major stationary source or the net emissions increase associated with a modification at an existing major stationary source is considered significant and the regulated pollutant would be subject to PSD review.

The proposed facility will be located approximately 7.1 km from SNP. Therefore, all regulated pollutants to be emitted from the proposed facility that were not initially identified as subject to PSD review based on their annual emission rate (i.e., tons per year) were evaluated. The maximum 24-hour average impacts for all other regulated pollutants are less than 1.0 $\mu g/m^3$ and are not subject to PSD review.

Ozone

Warren County is currently designated attainment for ozone based on the 1997 standard (0.08 parts per million (ppm)) and the 2008 standard (0.075 ppm). The 2008 standard is currently being reconsidered by EPA. Specifically, on January 6, 2010, EPA proposed to strengthen the NAAQS for ground-level ozone, the main component of smog. The proposed revisions are based on scientific evidence about ozone and its effects on people and the environment. EPA is proposing to strengthen the 8-hour "primary" ozone standard, designed to protect public health, to a level within the range of 0.060-0.070 ppm. EPA is also proposing to establish a distinct cumulative, seasonal "secondary" standard, designed to protect sensitive vegetation and ecosystems, including forests, parks, wildlife. At this point, the final outcome of this proposal is not known. The latest information at the time of public notice suggests that the new ozone standards may be finalized by the end of 2010.

The mitigation plan outlined in Condition 23 of the draft permit provides for NO_X emissions offsets or emissions reductions which are at least equivalent to those required in moderate ozone nonattainment area permitting (i.e., ratio of at least 1.15 to 1). The Best Available Control Technology (BACT) permit requirements are also at or near the Lowest Achievable Emission Rate (LAER) for the subject source as required in a nonattainment area.

VOC offsets are not required by current air regulations and are not contained in the permit. It is important to note that recent research demonstrates that rural regions and, in fact, most if not all of Virginia, are considered "NO_X limited" for the purposes of ozone formation. In other words, the concentration of ozone depends on the amount of NO_X in the atmosphere. This occurs when there is a lack of NO_2, thus inhibiting ozone titration when oxygen mixes with VOCs. In these regions, controlling NO_X would reduce ozone concentrations whereas controlling VOCs would have little if any effect on ozone formation.

Rural areas are usually NO_X limited due to the large amount of trees that produce relatively high concentrations of VOCs. For instance, the Blue Ridge Mountains are named in part because the high VOC levels reflect blue light. Regions that are "VOC limited" lack trees and are usually congested with high vehicular activity.

$PM_{2.5}$ Increment Analysis for Class I and Class II PSD Areas

EPA recently issued a final rule for PSD increment for $PM_{2.5}$ ("$PM_{2.5}$ Increment Rule", 40 CFR 52.12(b)(14(c)), 75 Federal Register 64864, 64890 (Oct. 20, 2010)). The $PM_{2.5}$ Increment Rule has a "trigger date" of one year from that publication (i.e., on October 20, 2011), at which time the increment will commence to be implemented through the PSD permitting process (*Id.* at 64887). After that date, a PSD permit applicant must demonstrate that emissions from the proposed source will not cause or contribute to a violation of PSD increment for $PM_{2.5}$ (*Id.* at 64887-64888). Computer modeling is used to determine in the permitting process whether a project causes or contributes to a predicted violation of PSD increment. EPA has stated to DEQ that the applicant is legally not required to make that demonstration if the permit is issued before the trigger date.

Even though the trigger date is not until October 20, 2011, the $PM_{2.5}$ Increment Rule establishes the date of publication, October 20, 2010, as the "major source baseline date." (*Id.* at 64887). New emissions from major stationary sources that occur after this date (i.e., the proposed Dominion Warren facility) will not be included in the baseline, but instead, will consume increment even though they are permitted before the trigger date (*Id.* at 64868 and 64887). Similarly, any reduction in emissions from a unit in the baseline after the major source baseline date will expand increment (*Id.* at 64868).

As previously stated, the applicant is not required to model for compliance with $PM_{2.5}$ increment before the trigger date. Furthermore, an increment analysis would typically not be initiated in the future unless an additional application is filed after the trigger date to permit a source located in an area that would require the inclusion of the proposed plant in future modeling, as a nearby increment-consuming source. In fact, should the proposed plant be approved and commence operations, its emissions would be included in the modeling inventory of existing sources at its actual operating rate (40 CFR, Part 51 App W Table 8-2).

Dominion volunteered to do the $PM_{2.5}$ increment modeling analysis at the suggestion of DEQ to get an understanding of what conditions would be necessary to comply upon the effective date of October 20, 2011. DEQ has reviewed and approved this analysis which is consistent with the approved modeling methodology contained in the permit application. The proposed facility has voluntarily accepted the limit below to comply with the $PM_{2.5}$ increment:

- The duct burners shall not operate between the hours of 10 pm and 5 am during the period between September and April.

DEQ advised the applicant that modeling could be required to demonstrate compliance after the trigger date. The applicant conducted the modeling early and has accepted the aforementioned conditions. DEQ has reviewed and approved this modeling and concurs that the restrictions will achieve compliance with the $PM_{2.5}$ increment at this time. The results of the analysis are provided in Table 11.

Table 11
$PM_{2.5}$ Increment Analysis for Class I and Class II PSD Areas

Pollutant	Averaging Period	Model Concentration ($\mu g/m^3$)(1)	PSD Increment ($\mu g/m^3$)	Complies (Y/N)?
Class II Area Modeling				
$PM_{2.5}$	24-hour(2)	2.17	9	Y
$PM_{2.5}$	Annual(3)	0.25	4	Y
Class I Area Modeling				
$PM_{2.5}$	24-hour(2)	1.95	2	Y
$PM_{2.5}$	Annual(3)	0.10	1	Y
(1) Worst-case modeled concentration over all ambient temperature/load conditions evaluated.				
(2) Highest second highest modeled concentration over the five modeled years.				
(3) Highest annual average modeled concentration over the five modeled years.				

Attachment A

Emission Rates and Stack Parameters

Worst-Case Data for Proposed Natural Gas-Fired Combined-Cycle Combustion Turbine Operation

Parameter		Value[1]			
Load (%)		100 w/ Duct Firing	100	75	60
Stack Height (ft)		175.0	175.0	175.0	175.0
Stack Diameter (ft)		22.0	22.0	22.0	22.0
Exit Temperature (°F)		191.20	197.70	191.50	185.00
Exit Velocity (ft/sec)		57.83	57.74	48.32	41.16
Heat Input (MMBtu/hr)		3,496	2,996	2,302	1,966
Pollutant Emissions Per Combustion Turbine (lb/hr)	SO_2	(2)	(2)	(2)	(2)
	PM_{10} 24 hour	21.16	15.51	11.92	10.18
	PM_{10} Annual[3]	19.38	19.38	19.38	19.38
	$PM_{2.5}$ 24 Hour	21.16	15.51	11.92	10.18
	$PM_{2.5}$ Annual[3]	19.38	19.38	19.38	19.38
	NO_X Annual[3]	24.18	24.18	24.18	24.18
	CO	17.41	9.91	7.61	6.50

(1) The values in the table represent the worst-case stack parameters and the emission rates for the four operating loads.

(2) Emission estimates indicate that SO_2 was not subject to PSD review. Therefore, an SO_2 modeling analysis was not performed.

(3) Annual emissions based on the worst-case emissions across all normal operations or normal operating plus SUSD. The following worst-case annual emissions will be annualized and modeled across all operating loads:

- PM_{10} – 84.89 tpy / 8760*2000 = 19.38 lb/hr
- NO_X – 105.90 tpy / 8760*2000 = 24.18 lb/hr

Source Parameters and Criteria Pollutant Emission Rates[1] For the Auxiliary Equipment

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr)				
					NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2
Inlet Turbine Chiller1[2]									
CHLR1	42.88	12.00	70.00	24.50	--	--	5.99E-03	1.84E-05	--
Inlet Turbine Chiller2[2]									
CHLR2	42.88	12.00	70.00	24.50	--	--	5.99E-03	1.84E-05	--
Inlet Turbine Chiller3[2]									
CHLR3	42.88	12.00	70.00	24.50	--	--	5.99E-03	1.84E-05	--
Auxiliary Boiler									
AUX_BLR	115.00	3.00	300.00	61.00	0.97	3.26	0.44	0.44	(3)
Fuel Gas Heater									
FGH	45.00	3.33	300.00	32.00	0.57	1.92	0.39	0.39	(3)

(1) Data provided by Dominion.
(2) The hourly emissions represent the emissions from a single cell of the 6-cell inlet turbine chiller.
(3) Emission estimates indicate that SO_2 was not subject to PSD review. Therefore, an SO_2 modeling analysis was not performed.

Source Parameters and Criteria Pollutant Emission Rates[1] For the Emergency Equipment

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr)[2]							
					NO_X	CO		PM_{10}		$PM_{2.5}$		SO_2
						1-hour	8-hour	24-hour	Annual	24-hour	Annual	
Diesel-Fired Emergency Generator												
DSL_GEN	115.00	1.23	987.00	135.00	0.14	12.62	1.58	0.06	0.0086	0.06	0.0086	(3)
Diesel-Fired Fire Water Pump Engine												
FWP	20.00	0.44	845.00	135.00	0.012	1.72	0.22	0.0083	0.0012	0.0083	0.0012	(3)

(1) Data provided by Dominion.
(2) Emissions rates were normalized based on the following equations:
Short-term Averaging Period – Emission Rate * (1/ Hours of Averaging Period)
Annual Averaging Period – Emission Rate * 52 hours per year / 8,760
(3) Emission estimates indicate that SO_2 was not subject to PSD review. Therefore, an SO_2 modeling analysis was not performed.

Short-Term Averaging Period Startup Summary[1]

	Offline	Start	Normal	Total	Start	Normal	Total
	min	min	min	min	lb	lb	Lb
				CO 1-hour			
Turbine 1	0	60	0	60	813.90	0	813.90
Turbine 2	60	0	0	60	0	0	0
Turbine 3	60	0	0	60	0	0	0
Startup Total							813.90
Normal Operation Total[2]							52.23
				CO 8-hour			
Turbine 1	0	252	228	480	2205.30	66.16	2271.46
Turbine 2	252	101	127	480	804.20	36.85	841.05
Turbine 3	353	101	26	480	804.20	7.54	811.74
Startup Total							3924.25
Normal Operation Total[2]							417.84
				PM_{10} 24-hour			
Turbine 1	0	252	1188	1440	23.30	418.97	442.27
Turbine 2	252	101	1087	1440	8.90	383.35	392.25
Turbine 3	353	101	986	1440	8.90	347.73	356.63
Startup Total							1191.15
Normal Operation Total[2]							1523.52
				$PM_{2.5}$ 24-hour			
Turbine 1	0	252	1188	1440	23.30	418.97	442.27
Turbine 2	252	101	1087	1440	8.90	383.35	392.25
Turbine 3	353	101	986	1440	8.90	347.73	356.63
Startup Total							1191.15
Normal Operation Total[2]							1523.52
				NO_X 24-hour[3]			
Turbine 1	0	252	1188	1440	115.10	501.34	616.44
Turbine 2	252	101	1087	1440	77.00	458.71	535.71
Turbine 3	353	101	986	1440	77.00	416.09	493.09
Startup Total							1645.24
Normal Operation Total[2]							1823.04
				SO_2 24-hour[3]			
Turbine 1	0	252	1188	1440	1.28	19.40	20.68
Turbine 2	252	101	1087	1440	0.49	17.75	18.24
Turbine 3	353	101	986	1440	0.49	16.10	16.59
Startup Total							55.52
Normal Operation Total[2]							70.56

[1] Startup emissions presented are for the proposed combustion turbines.
[2] Normal operation emissions correspond to those for 100% load with duct burners.
[3] NO_X 24-hour and SO_2 24-hour calculated for determining if additional Class I visibility modeling is needed for startup.

Stack Parameters and Modeled Emission Rates

Operating Mode	Exit Velocity (fps)	Exit Temp. (°F)	CO 1-hour (lb/hr) Turbine 1	CO 1-hour (lb/hr) Turbine 2	CO 1-hour (lb/hr) Turbine 3	CO 8-hour (lb/hr) Turbine 1	CO 8-hour (lb/hr) Turbine 2	CO 8-hour (lb/hr) Turbine 3	$PM_{10}/PM_{2.5}$ 24-hour (lb/hr) Turbine 1	$PM_{10}/PM_{2.5}$ 24-hour (lb/hr) Turbine 2	$PM_{10}/PM_{2.5}$ 24-hour (lb/hr) Turbine 3
Startup											
Cold Start[(1)(2)]	37.92	185.00	813.90	NA	NA	275.66	NA	NA	0.97	NA	NA
Warm Start[(1),(2)]	37.93	185.00	NA	NA	NA	NA	100.53	100.53	NA	0.37	0.37
Normal Operation[(3)]	57.83	191.20	NA	NA	NA	8.27	4.61	0.94	17.46	15.97	14.49

(1) Average exhaust velocity during startup, provided by vendor and/or Dominion.
(2) Lowest exit temperature for 60% load from performance data provided by vendor and/or Dominion.
(3) Exit velocity and temperature for the 100% load with duct burner from performance data provided by vendor and/or Dominion.

Annual Averaging Period Startup Summary

Operating Mode	hr/yr	NO_X lb/hr	NO_X tpy	PM_{10} lb/hr	PM_{10} tpy
Startup					
Offline	1,728	0.00	0	0.00	0
Without duct burning	811	21.70	8.8	15.51	6.3
With duct burning	6,000	25.32	76.0	21.16	63.5
Hot start	125	83.86	5.2	5.72	0.4
Warm start	25	45.74	0.6	5.29	0.1
Cold start	25	27.40	0.3	5.55	0.1
Shutdown	46	102.00	2.3	5.57	0.1
TOTALS	8,760		93.2		70.4
Normal Operation					
100% load					
Without duct burning	2,760	21.70	29.9	15.51	21.4
With duct burning	6,000	25.32	76.0	21.16	63.5
TOTALS	8,760		**105.9**		**84.9**
100% load w/o duct burners	8,760	21.70	**95.0**	15.51	**67.9**

Stack Parameters and Modeled Emission Rates for Annual Pollutants

Operating Mode	Exit Velocity (fps)	Exit Temp. (°F)	NO_X Annual (lb/hr)			$PM_{10}/PM_{2.5}$ Annual (lb/hr)		
			Turbine 1	Turbine 2	Turbine 3	Turbine 1	Turbine 2	Turbine 3
Startup(1),(2)	32.375	184.90	1.93	1.93	1.93	0.14	0.14	0.14
Normal Operation(3)								
100% with Duct Burner	57.83	191.20	19.35	19.35	19.35	15.93	15.93	15.93
100%	57.74	197.71	19.35	19.35	19.35	15.93	15.93	15.93
75%	48.32	191.50	19.35	19.35	19.35	15.93	15.93	15.93
60%	41.16	185.00	19.35	19.35	19.35	15.93	15.93	15.93

(1) Average exhaust velocity across all types of startups and shutdown, provided by the vendor and/or Dominion.
(2) Lowest exit temperature for 60% load from performance data provided by vendor and/or Dominion.
(3) Exit velocity and temperature from performance data provided by vendor and/or Dominion.

Attachment B

Class I Area Visibility Analysis Results

Number of Excursion Hours for Each Viewpoint Using FLAG Visibility Thresholds

Predicted Number of Excursion Hours Over 5 Years (at least one visibility parameter exceeding significance threshold) 3 Gas-Fired Turbines						
Wind from (degrees) -->	**0**	**10**	**20**	**30**	**Total**	**Percentage of Daytime Hours (%)**
Shenandoah Valley Overlook	5	(1)	(1)	0	5	0.02%
Dickey Ridge	94	(1)	(1)	0	94	0.43%
Signal Knob Overlook	99	(1)	(1)	16	115	0.52%
Compton Gap Road	(1)	32	16	2	50	0.23%
Lands Run Road Gate	(1)	(1)	26	0	26	0.12%
Excursion Hours(2)	114	32	27	16	189	

(1) Indicates that results for the given wind direction and viewpoint were not taken into account because the viewpoint is within 10° of the downwind axis of the source.
(2) Number of non-overlapping hours with a parameter excursion at one or more observation points.

Distribution of Excursion Hours for |C| and ΔE

Predicted Number of Excursion Hours Over 5 Years (|C| and ΔE for sky or terrain exceeding significance threshold) 3 Gas-Fired Turbines											
Observation Point -->	**Compton Gap Road**			**Dickey Ridge**		**Signal Knob Overlook**		**Lands Run**		**Shenandoah Valley Overlook**	
Wind from degrees/north -->	**10**	**20**	**30**	**0**	**30**	**0**	**30**	**20**	**30**	**0**	**30**
Hours with Contrast Excursions											
Sky Background	3	0	0	2	0	3	0	5	0	5	0
Terrain Background	32	16	2	94	0	99	16	26	0	0	0
Contrast Total	32	16	2	94	0	99	16	26	0	5	0
Hours with delta E Excursions											
Sky Background	0	0	0	7	0	9	0	5	0	4	0
Terrain Background	15	5	1	22	0	36	11	15	0	0	0
Delta E Total	15	5	1	25	0	36	11	16	0	4	0
Total Excursion Hours	**32**	**16**	**2**	**94**	**0**	**99**	**16**	**26**	**0**	**5**	**0**

Refined Number of Excursion Hours for Each Viewpoint Accounting for Realistic Visibility Parameter Thresholds

Predicted Number of Excursion Hours Over 5 Years Based on the Apparent Plume Width (at least one visibility parameter exceeding significance threshold) 3 Gas-Fired Turbines						
Wind from (degrees) -->	0	10	20	30	Total	Percentage of Daytime Hours (%)
Shenandoah Valley Overlook	3	(1)	(1)	0	3	0.01%
Dickey Ridge	16	(1)	(1)	0	16	0.07%
Signal Knob Overlook	27	(1)	(1)	2	29	0.13%
Compton Gap Road	(1)	13	4	0	17	0.08%
Lands Run Road Gate	(1)	(1)	8	0	8	0.04%
Excursion Hours(2)	33	13	8	2	56	

(1) Indicates that results for the given wind direction and viewpoint were not taken into account because the viewpoint is within 10° of the downwind axis of the source.
(2) Number of non-overlapping hours with a parameter excursion at one or more observation points.

Summary of PLUVUE II Modeling Results as Provided by the National Park Service

View Point	Total During 5-Year Period			Annual Average		
	Days	|C| Hours	ΔE Hours	Days	|C| Hours	ΔE Hours
Signal Knob Overlook	26	29	5	5	6	1
Dickey Ridge	14	16	3	3	3	1
Compton Gap Road	14	15	0	3	3	0
Lands Run Road Gate	8	8	5	2	2	1
Shenandoah Valley Overlook	3	3	0	1	1	0
Totals	65	71	13	14	15	3